E-00000D-02-0065

PANDA GILA RIVER, L.P. PROPOSED CHANGES TO DRAFT SECOND BIENNIAL TRANSMISSION ASSESSMENT REPORT

1. Overview of Assessment

1.1 Assessment Authority

Arizona statutes require every organization contemplating construction of any transmission line within Arizona during a ten-year period to file a ten-year plan with the Arizona Corporation Commission (ACC) on or before January 31 of each year[1]. In 1999, the Arizona state legislature placed a statutory obligation with the ACC to biennially review the plans filed with the Commission and "issue a written decision regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner"[2].

In 2001, the Arizona legislature further modified the Arizona Power Plant and Transmission Line Siting statutes resulting in two new statutory requirements related to filing of plans with the Commission. Every organization contemplating construction of a new power plant within Arizona is now required to file a plan with the Commission ninety days before filing for an application for a Certificate of Environmental Compatibility ("CEC").[3] Secondly, all plans filed with the Commission are to be accompanied by power flow and stability analysis reports showing the effect of plant interconnections on the current *(and future)* Arizona electric transmission system.

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[1] ACC Rule A.R.S. 40-360-02

[2] ACC Rule 1606.B

[3] ARS Section 40-360-02-B

1.2 First Biennial Transmission Assessment

The Utilities Division Staff ("Staff") of the ACC initiated its first biennial transmission assessment of existing and planned transmission system in 2000. A written decision of that assessment was rendered in July 2001. In its first biennial transmission assessment, Staff determined the adequacy of existing Arizona transmission lines and additions planned between 2000 and 2010. Staff investigated the ability of Arizona's transmission system to adequately deliver energy to the state's retail consumer markets as well as import energy from or export energy to the regional transmission grid with which it is interconnected. Staff's report was filed under Docket No. E-00000A-01-0120, and is also located on the ACC website.[53]

Staff concluded in its first biennial transmission assessment that the State of Arizona did not have adequate existing or planned transmission facilities to deliver the energy needs of the state in a reliable manner. The planned transmission enhancements were found to be both inadequate and untimely. These conclusions were based upon the following findings:

- There was very little additional long-term firm regional transmission capacity available to export or import energy over Arizona's transmission system.
- Southeastern Arizona utilities relied upon restoration of service rather than continuity of service following transmission outages due to service via radial transmission lines.
- There were transmission import constraints for three geographical load zones in Arizona: the Phoenix metropolitan area, Tucson, and Yuma. Planned transmission enhancements fail to resolve this situation in a timely manner.
- The existing and planned additions to the Palo Verde transmission system fail to accommodate the full output of all new power plants proposing to interconnect at Palo Verde, requiring procedures to be developed for curtailment and scheduling restriction.
- Some proposed power plants are being interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than continuing Arizona's best engineering practice of multiple lines emanating from power plants.

Staff recommended in its first Biennial Transmission Assessment the following two different standards for the measurement of transmission adequacy and security due to the different environment of electricity industry restructuring:

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[53] http://www.cc.state.az.us/utilities/electric/biennial/xmn.pdf

1. There should be sufficient transmission import capacity to reliably serve all loads in a utility's service area without limiting access to more economical or less polluting remote generation.

   Staff is not suggesting that local generation or distributed generation should be excluded from a utility's resource mix. This is evidenced by the fact that Staff has supported local generation in the siting hearings for the Kyrene and Santan plants. Staff did not intervene in the West Phoenix siting hearing, but staff supports the project.

2. New power plants must have sufficient interconnected transmission capacity to reliably deliver its full output without use of remedial action schemes or displacing a priori generation at the same interconnection for single contingency (N-1) outages.

1.3 Purpose and Framework of the Second Biennial Assessment

This second Biennial Transmission Assessment (BTA) is undertaken by Staff to fulfill the statutory obligation to biennially review the plans filed with the Commission. The 2002-2011 transmission plans filed in January 2002 under Docket No. E-00000D-02-0065 are the subject of this assessment. Of particular interest is the corrective actions taken by the industry to resolve conclusions identified in the Staff's first BTA.

Adequacy and security of an existing or planned transmission system cannot be determined by merely reviewing the Ten-Year Transmission Plans filed with the Commission. The reliability of an existing or planned electric system under existing, alternative or future operating conditions can only be determined by technical simulation studies. Such studies require the application of a set of study criteria to measure the system's performance. Staff once again used a set of guiding principles to aid in its determination of adequacy and reliability of power plant and transmission line projects. A copy of these guiding principles is attached as Appendix A. Staff's guiding principles are based upon best engineering practices established in Arizona[6] coupled with the use of regional[4] and national reliability council[5] criteria and standards.

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[6] Jerry D. Smith, ACC, "Arizona's Best Engineering Practices", Staff pre-filed comments for the Gila Bend Power Plant Hearing, Docket No. L-00000V-00-01016, November 9, 2000

[4] WECC Reliability Criteria found at http://www.wecc.com

[5] NERC Planning Standards found at http://www.nerc.com

Each utility distribution company also has an obligation to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers in its service area. Staff used these guiding principles, criteria and standards for this biennial transmission assessment. This requirement is also coupled with the ~~stipulation to~~requirement that Arizona utilities competitively procure ~~50% of its~~100% of their standard offer ~~obligations.~~requirements, with at least 50% procured through competitive bidding.

Staff has again relied on analyzing the technical reports and documents filed with the Commission by the various organizations rather than performing technical studies of their own. To assist Staff in this effort, Staff hired a consulting organization, P Plus Corporation from California, for this second biennial transmission assessment. P Plus Corporation (PPC) assisted Staff in the following work areas:

PPC assumed a lead role in reviewing and analyzing technical study reports already collected by Staff and applicable to the Arizona transmission system, with dates succeeding the Commission's first biennial assessment. These study reports include, but are not limited to:

- Reports filed as exhibits for new power plants and transmission projects approved for construction in Arizona via Siting cases, or reports accompanying a party's 2001 and 2002 ten-year plans filed with the Commission by January 31, 2002.
- Numerous studies performed by NERC, WSCC, NARUC, Western Governor's Association, RTOs, state regulatory agencies, and any electric industry workgroup or local utility.

Staff was able to assemble and review a broad spectrum of information and technical reports addressing transmission assessments from a national, Western Interconnection (WI), regional, state and local utility perspective. All referenced technical material is listed in Appendix D of this report.

PPC organized and facilitated a two-day workshop on July 30 and 31, 2002 relative to the second biennial transmission assessment. The recent study results and transmission plans from transmission providers and new merchant plant developers were presented and discussed at the workshop. The workshop presentation materials are located on the ACC website.[55]

Staff and PPC utilized the workshop proceedings along with the reports filed with the Commission in performing this second biennial transmission assessment.

PPC and Staff made use of a three-stage process to facilitate the electric industry's participation in the Commission's second biennial transmission assessment. An overview of that process is described below. **In the first stage of the process**, ACC organized and held a two-day workshop on July 30 and 31, 2002, to get updates from:

- Transmission Providers on transmission expansion related activities to ensure adequate load serving capability for native load customers, and to ensure power grid reliability for future years.
- Merchant Plant Developers on transmission interconnection studies and on actual plant performance.

The recent study results and transmission plans were presented and discussed at the workshop. The workshop presentation materials are located on the ACC website.[55]

The workshop participants included Arizona Transmission Providers, Merchant Plant Developers, members of the Siting Committee, and the Service List members. The list of workshop participants is included in Appendix E.

In order to facilitate focused and meaningful presentations and discussions at the workshop, Staff requested Transmission Providers and Merchant Plant Developers to come prepared to discuss the following topics at the workshop.

Transmission Providers:

- An update on Ten Year Transmission Plans, giving details on the transmission additions/upgrades/revisions since the first biennial transmission assessment.

[55] http://www.cc.state.az.us/meetings/agendas/ag07-30s.htm

[55] http://www.cc.state.az.us/meetings/agendas/ag07-30s.htm

- Parties involved in Central Arizona Transmission (CATS) studies were requested to provide an update on the EHV Transmission system studies, and the new HV study of the 230kV / 115kV system between Phoenix and Tucson being facilitated by Arizona Power Authority (APA).
- Updates on the State of Arizona EHV Transmission projects and studies such as the PV Hub Risk Assessment, Palo Verde Area Transmission studies and Navajo Transmission project.
- Updates on the import constraints in the five load pockets, namely, Phoenix, Tucson, Yuma, Santa Cruz County, and Mohave County.
- Updates on the local transmission issues in the local areas, namely, Central Arizona, Northern Arizona, Southeastern Arizona, and Southern Arizona.

Merchant Plant Developers:

- Updates on Ten Year generation expansion Plans filed with the ACC, giving details on plant/unit additions, capacity revisions, and plant/unit refurbishment since the first biennial transmission assessment.
- Updates on the operational experience of the plants in operation
- Updates on the status of their ongoing projects, including status of construction and commencement of operation
- Updates on the technical study results related to Siting/Compliance filing requirements related to ACC's Certificate of Environmental Compatibility (CEC) which, among others, include updates on self-certification and WECC RMS requirements.

With regard to the above requests, Staff's assessment is that the Transmission Providers met Staff's needs, whereas the responses from some, but by no means all, Merchant Plant Developers were not as thorough.

The workshop provided an informal setting to promote effective discussions on the presentations from transmission providers and merchant plant developers.

The first draft of the report on the Second Biennial Transmission Assessment (BTA) is based on the analysis of the reports and documents filed with the Commission by the Transmission Providers and Merchant Plant Developers[23-47], the July 30 and 31 Workshop material[48-49] and participants responses to questions raised at the workshop.

The second stage of the process in the second BTA is to provide the first draft of the report for industry review and comment.

The third stage of the process is to hold a second workshop on September 25, 2002, to facilitate Staff to respond to industry comments on the first draft of the report.

[23-47] Ten-Year Plans filed with ACC

[48-49] Transcription of Workshop proceedings

After the second workshop on October 8, the draft report will be revised to incorporate the discussions, suggestions and comments from the industry participants at the workshop.

The details of the transmission assessment are presented in Sections 5 through 10.

2. Related Industry Activities

This section describes various electricity industry activities that have occurred since Staff's first Biennial Transmission Assessment. Only those electricity industry initiatives and activities related to transmission infrastructure, transmission grid expansion at regional and sub-regional levels, transmission congestion, transmission reliability, and transmission rights and pricing are described. This section considers how such industry activities relate to the transmission expansion, siting and analysis in the state of Arizona.

2.1 FERC Standard Market Design

The US Federal Energy Regulatory Commission (FERC) proposed on July 31, 2002, a Standard Market Design (SMD) to standardize the structure and operation of competitive wholesale power markets, and to reform and prevent exercise of transmission market power. SMD expands on FERC Order No. 2000's encouragement of all transmission owners to transfer control of their transmission facilities to ~~operate independently.~~independent operators. The SMD is intended to restore confidence in competitive power markets by assuring adequate generation resources and establishing a standard framework for market transactions and a single form of transmission services.[7] FERC anticipates that the SMD Notice of Proposed Rulemaking (NOPR) would be approved in February 2003.

SMD's fundamental market elements include active monitoring and mitigation to prevent market abuses, spot market (or day-ahead market) that complements a market for long-term power supplies, with price discovery and market transparency.

FERC also claims its SMD is designed to prevent the following forms of discrimination in today's wholesale electric markets:

- Preference for Native Load Growth

[7] Federal Energy Regulatory Commission, Standard Market Design, July 31, 2002, Docket No. RM01-12-000

- Delays in Requests for Service
- Scheduling advantages
- Imbalance resolution
- Inaccurate Posting of available capacity
- OASIS postings (what is meant by this?)
- Capacity benefit margin manipulation
- ~~Discretionary~~Abuse of discretionary Transmission Loading Relief procedures
- Enron-type trading strategies

Under the SMD, Independent Transmission Providers (ITPs) will administer spot markets for wholesale power, ancillary services and transmission congestion rights, a real-time "balancing" market to maintain reliable operations of the power grid, and a separate "day-ahead" market. These will complement bilateral contracts for long- and short-term energy purchases.

FERC states that the market standardization proposal proclaims to create the following:

- New Transmission Tariff with Congestion Pricing: Creates a market for financial transmission rights, and lets the market assign a value to the congestion that signals investment needed to relieve the bottleneck. Incorporates Locational Marginal Pricing (LMP), which provides price signals indicating where investment in generation and transmission is needed to improve grid operations. LMP minimizes opportunities for market manipulation.
- SMD provides an incentive for power grid enhancement by allowing the companies that invest in new transmission to retain the financial rights to the added power transfer capacity.
- The congestion pricing and management approach should dramatically reduce the need for curtailment of transactions as a means of preserving power-grid reliability/operability.
- All transmission uses under a single network tariff, that is, transmission service in support of both wholesale and retail transactions will fall under a common tariff.
- Generation Resource Adequacy: The design requires "Load-serving entities" to arrange sufficient supply and demand reduction resources to meet peak demand plus 12% reserve margin.
- Demand Responsiveness: The design proposes that Demand reduction to meet generation adequacy requirement be bid into the spot market in addition to power supply.
- Efficient Rate design: With seamless trading across regional markets and between markets, avoid pancaked rates for customers.
- Market Monitoring and Price mitigation: Each ITP –administered regional power market will have an independent market monitor to alert about anti-competitive problems.

Market administrators will have price mitigation tools to impede market manipulation efforts.

FERC's SMD is being reviewed by all the utilities in the state of Arizona regarding its applicability to their situation, its effectiveness for non-discriminatory transmission services, and the implications of Locational Marginal Pricing (LMP) as a congestion management tool. Similarly, the Commission is also reviewing FERC's proposal along with other state utility regulators to ascertain in what ways the SMD solves actual local and regional transmission delivery concerns, adequately manages market abuses, assures consumers reliable service at reasonable and prudent prices, and avoids dual jurisdictional creep.

2.2 Department of Energy National Grid Study

The U.S. Department of Energy (DOE) conducted an independent assessment of the electric transmission system in 2001 to examine the benefits of establishing a national transmission grid and to identify the transmission bottlenecks and measures to address them[8]. The study concluded that eliminating transmission constraints or bottlenecks is essential to ensuring reliable and affordable electricity. The inter-regional transmission congestion costs consumers hundreds of millions of dollars annually, and relieving these bottlenecks could save consumers millions of dollars annually.

The DOE report contains the following recommendations:

- Increase regulatory certainty by completing the transition to competitive regional wholesale markets.
- Develop a process for identifying and addressing transmission bottlenecks of national interest.
- Avoid or delay the need for new transmission facilities by improving system operations and fully utilizing the existing facilities. Regional planning processes must consider transmission and non-transmission alternatives to eliminate bottlenecks.
- Opportunities for customers to reduce the electricity demands voluntarily, and targeted energy efficiency and distributed generation should be coordinated within regional markets.

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[8] USDOE National Transmission Grid Study, May 2002

- Ensure mandatory compliance with reliability rules by including enforceable penalties for non-compliance.
- DOE should take increased leadership role in Transmission R&D.

The DOE study determined that as a result of supply and demand patterns, utilities in the West rely more on transporting electricity over long distances to meet local demand than in the East. Electricity trade as a percentage of demand in the West reaches nearly 30% during some periods.

The DOE study is of particular relevance to this project in that it emphasizes the study and analysis of the transmission grid to relieve bottlenecks.

2.3 Western Governors Association Efforts

The Western Governors Association (WGA) performed a western market and infrastructure assessment and addressed the factors affecting electric reliability and prices.[9]

Some of the key points made by that Group that are relevant to this project are summarized below:

- The overall energy infrastructure in the West is insufficient relative to the projected energy demand, and additional infrastructure expansions are needed to support a competitive market.
- Imports and exports of electricity between regions are limited by constrained transmission paths.
- The timing of the Southwestern region's economic recovery will be pivotal to determining the adequacy of the infrastructure to satisfy the corresponding increase in electricity and natural gas demand.
- Transmission bottlenecks constrain the efficient distribution of resources and directly affect cost differentials.
- RTO participation should be supported for consistent, non-discriminatory grid management.
- New Transmission construction has to be expedited in congested areas.
- Any expansion of the transmission system must maintain reliability, support both load and resource diversity in the western interconnection, and enable an efficient wholesale

[9] Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association, August 2001

electricity market. Without the transmission expansion projects, the existing transmission system may not be adequate to meet peak load, integrate new planned generation and maintain sufficient levels of reliability.

- Increasing the energy trading over transmission systems must not reduce system reliability.
- System reliability is maintained by establishing and implementing rigorous standards for system operations and planning. Transmission system operators are responsible for maintaining adequate reserves on-line and keeping line flows within established ratings.

Many of the factors above are germane to evaluating the adequacy and reliability of the transmission system of Arizona.

2.4 Western Electricity Coordinating Council (WECC)

Western Electricity Coordinating Council (WECC) was formed in 2001 through the consolidation of the former Western Systems Coordinating Council (WSCC) that had responsibility for addressing the reliability issues of the West, and the Regional Transmission Associations (RTAs) that were dealing with the commercial practices of the West. WECC is one of the nine regional councils of the North American Electric Reliability Council (NERC).

WECC provides the coordination that is essential for operating and planning a reliable and adequate electric power system for the western region of the continental USA, Canada, and Mexico. WECC continues to focus its efforts on promoting the reliability of the interconnected bulk power system, which is comprised of transmission systems 230 KV and above. Criteria have been developed and adopted for use by member systems for day-to-day operation and system planning. As the electricity industry undergoes changes, WECC has taken proactive steps to implement an open process for membership and criteria modifications.

The member systems' transmission facilities are planned in accordance with the "WECC Reliability Criteria for Transmission System Planning[10], which establishes the performance levels intended to limit the adverse effects of each member's system operation on others, and recommends that each member system provide sufficient transmission capability to serve

[10] WECC Reliability Criteria for Transmission System Planning, May 2001

customers, to accommodate planned inter-area transfers, and to meet its transmission obligation to others.

WECC has established a process to manage compliance with the established criteria. This process includes Compliance monitoring, annual study reports, project review and rating process, and operating transfer capability policy group process. In addition, through a Reliability Management System (RMS) agreement, compliance is ensured with regard to control performance, operating reserve and operating transfer capability, and disturbance control[11]. RMS includes the requirements to system operators for availability of major transmission path operating limits. Also WECC addresses unscheduled flow mitigation scheme approved by FERC.

The transmission planning activities in the State of Arizona have to be performed in a coordinated manner with other members of the Western system in accordance with the WECC standards, guidelines, and compliance requirements.

2.5 ACC Generic Electric Restructuring

The Commission issued a procedural order on January 22, 2002, which opened a generic docket on electric restructuring[12]. A subsequent procedural order issued on February 8, 2002, served the purpose of consolidating the generic docket with the following related cases already active before the Commission:

- Docket No. E-01345A-01-0822, APS variance request to A.A.C. R14-2-1606,
- Docket No. E-01933A-02-0069, TEP variance request to certain competition rule compliance dates,
- Docket No. E-01933A-98-0471, TEP application for approval of its stranded cost recovery, and
- Docket No. E-00000A-01-0630, Proceedings concerning the Arizona Independent Scheduling Administrator (AzISA).

[11] WECC Reliability Management System (RMS) Agreement found at http://wecc.com

[12] ACC Staff Report on the Generic Electric Restructuring, Docket No. E-00000A-02-0051, March 22, 2002

Commissioners posed a variety of questions relating to electric restructuring in the generic restructuring case. A Staff Report was issued on March 22, 2002 that summarized intervening parties' responses to the Commissioners' questions and contrasted Staff's own responses to the same questions. The report documented the experience of other states that have or are undergoing electric restructuring. The Staff report also addressed the following topics: 1) status of retail competition in Arizona, 2) competitive resource bidding, 3) transmission access and constraints, 4) distributed generation, 5) stranded utility investments, 6) market power of transmission providers and utilities owning generation assets, 7) the role of the AzISA and regional transmission organizations (RTO) forming in the west, and 8) the impact of recent market events.

~~A~~Following a Special Open Meeting to consider the APS and TEP variance requests, the Commission issued a procedural order~~was issued~~ on May 2, 2002, ~~that set in motion~~staying the hearings scheduled in the variance proceedings and establishing two concurrent tracks ~~of~~to review~~of~~ major restructuring issues. Issues identified by the Commission for consideration in "Track A" were market power concerns, transfer of utility generation assets, Code of Conduct and Affiliate Interest Rules, and jurisdictional concerns. The concurrent "Track B" was established to consider competitive procurement of resources. Track B proceedings ~~are~~were still in progress at the time this report was written.

Track A proceeding concluded with a decision rendered by the Commission on September 6, 2002.[56] The opinion and order approved by the Commission was in general agreement with Staff's recommendations on transmission issues and encouraged an industry-wide planning process to resolve transmission constraints.[57] The Commission also believes that both transmission providers and merchant power plants should share the burden and obligation to resolve Arizona's transmission constraints.

[56] Decision No. 65154, Docket No. E-00000A-02-0051, et al., September 6, 2002

[57] Ibid, page 25 at line 23.

Commission retail electric competition rules, in place since January 1, 1999, require that at least 50% of the power supply for Standard Offer Service by an investor owned utility distribution company (UDC) will be purchased through a competitive bid process.[2] That same UDC has the obligation to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within its service area.[54] ~~Direct testimony of Staff~~At the hearing,~~witness Jerry Smith and corroborating rebuttal testimony of~~ APS witness Cary Deise ~~established~~agreed that all generators designated network resources, including both utility and merchant generators, would have access to transmission currently used by the utilities to serve their native load customers. Staffs witness Jerry Smith and APS witness Cary Deise testified that existing transmission constraints in Arizona will limit APS' (and TEP's) ability to deliver competitively procured supply to less than the required 50% of Standard Offer Service load.~~Testimony also established that the same conclusion applied to TEP. Transmission constraints also limitTEP's ability to deliver competitively procured power to its service area.~~ The transmission constraints limiting APS' and TEP's ability to comply with the aforementioned Commission rules results from their dependence upon local reliability-must-run (RMR) generation to serve their peak load during certain hours of the year. In its Track A order, the Commission required APS and TEP to competitively procure no less than all of their Standard Offer Service requirements that they could not supply from utility-owned resources.[1]

The Track A order stipulates that APS and TEP are to work with Staff to develop a 2002 study process to resolve RMR generation concerns and that such study plan results are to be included in the 2004 Biennial Transmission Assessment.[58] This includes studying and analyzing the merits of existing dependence on RMR generation instead of building transmission to resolve transmission import constraints and the merits of any future contemplated utilization of RMR to defer transmission projects. Until the 2004 Biennial Transmission Assessment is issued with RMR study plan results resolved, APS and TEP are to file annual RMR study reports with the Commission in concert with their January 31 annual ten-year plan for review prior to implementing any new RMR generation strategies.[59]

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[2] ACC R14-2-1606-B

[54] ACC R14-2-1609.B

[1] For this analysis, APS generation *does not* include the Redhawk and West Phoenix units owned by PWEC.

[58] Decision No. 65152, Docket No. E-00000A-02-0051, et. al., September 2002

[59] Ibid, Finding of Fact 41

3. Transmission Planning Standards and Processes

Individual utilities within the state of Arizona plan and design their bulk transmission systems in accordance with the WECC regional Reliability Criteria for System Planning and Minimum Operating Reliability, guidelines established at the state level, and their own internal planning criteria, guidelines and methods. These planning practices are developed to ensure that the systems are planned to provide reliable service to customers under various system conditions. In addition, it ensures that neighboring utilities and neighboring states plan their systems in a coordinated manner by following a consistent set of standards, guidelines and criteria in order to provide economical and reliable supply of electricity.

3.1 NERC/WECC Planning Standards

The reliability of interconnected bulk electric systems is defined by NERC with two terms: Adequacy and Security. Adequacy is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.[17]

Security of a system is judged by its ability to accommodate the loss of a single system element, including its largest single hazard: a generator, transmission line or transformer. This is referred to as a single contingency criteria or (N-1) criteria. The system is judged to be secure if the system response to even the most critical single contingency is such that system adequacy is maintained and system parameters such as frequency, voltage and power flows remain within predetermined acceptable ranges. System security is achieved by maintaining sufficient generation reserves and sufficient transmission capacity throughout the electric system to enable loss of the most critical single contingency while maintaining an adequate system supply and delivery of energy to all customers. A higher level of system security is achieved when an

[17] WSCC: NERC/WSCC Planning Standards, revised August 7, 2002

adequate supply and delivery of energy to consumers is maintained for disturbances involving the loss of multiple system components.

While these definitions might have been appropriate for the traditional, regulated environment of the past, the new competitive electricity environment is fostering an increasing demand for transmission services, and new definitions of reliability might be needed. With the focus of transmission systems to support increased competitive electric power transfers, electrical limitations of transmission systems and their capability to support a wide variety of transfers take on a new significance.

In the new competitive environment, the challenge is to plan and operate the future transmission systems to provide the requested power transfers while maintaining overall system reliability. Hence, all industry participants must recognize the importance of planning their systems in a manner that promotes reliability.

It is Staff's opinion that these definitions of Adequacy and Security also do not take into consideration the environmental impact of older and more polluting generation. Furthermore, the regional and federal reliability criteria do not apply to the internal systems of utilities. Staff believes that a better approach is to have standards of measuring transmission capacity instead of merely defining the terms "transmission adequacy" and "security".

To maintain the reliability of bulk systems, the regions and their members are required to comply with the NERC planning standards[17]. NERC/WECC stipulates that the systems must be planned, designed and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes of delivering electric power to areas of customer demand, providing flexibility for changing system conditions, reducing installed generating capacity, and allowing economic exchange of electric power among systems.

[17] WSCC: NERC/WSCC Planning Standards, revised August 7, 2002

Electric power transfers have a significant effect on the reliability of interconnected transmission systems, and must be evaluated in the context of other functions of the system. In some areas, portions of transmission systems might get loaded to their stability limits.

In the planning of transmission systems, NERC/WECC stipulate that the systems should be planned to move electricity from areas of generation to areas of demand under a variety of expected system conditions (e.g., forced and planned outages, varying demands, etc.), while continuing to operate reliably within equipment and electric system thermal, voltage and stability limits. In addition, NERC/WECC stipulate that electric systems must be planned to withstand the more probable forced and planned outage system contingencies at projected customer demand and anticipated electricity transfer levels.

In addition, NERC/WECC Guides for planning are of relevance to planning transmission at a regional level.[17]

Some of the guidelines of relevance to AZ transmission planning are described below:

- The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve reliability benefits of interconnected systems.
- Studies affecting more than one system owner or user should be conducted on a joint basis.
- The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.
- The interconnected transmission systems should be planned to avoid excessive dependence on any one circuit or substation.
- Reliability assessments should examine post-contingency steady state conditions as well as stability, overload, cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm transmission services.
- Annual updates to transmission assessments should be performed, as needed, to reflect anticipated changes in system conditions.

[17] WSCC: NERC/WSCC Planning Standards, revised August 7, 2002

3.2 WECC Minimum Operating Reliability Criteria

For reliable operation of the western interconnection, WECC requires all entities to comply with the WECC Minimum Operating Reliability Criteria (MORC). MORC is applicable to system operation under all conditions even when facilities required for secure and reliable operation have been delayed or forced out of service.[18]

MORC principles applicable to the transmission system operation are summarized below:

- The interconnected power system shall be operated at all times so that system instability, uncontrolled separation, cascading outages, or voltage collapse will not occur as a result of single or multiple contingencies of sufficiently high likelihood.
- Continuity of service to load is the primary objective of the MORC. Preservation of interconnections during disturbances is a secondary objective except when preservation of interconnections will minimize the magnitude of load interruption.

Since electric system reliability is so vital to Arizona, Staff contends that it is appropriate to apply the most specific and stringent criteria, WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) page III-27).

3.3 Regional Planning: Seams Steering Group (SSG)-WI Planning Work Group

A Seams Steering Group (SSG) -Western Interconnection (WI) committee was formed and consists of representatives from three RTOs: WestConnect, CAISO, RTO West. The SSG-WI is facilitating review of functional issues related to coordinating and developing the interface between CAISO and any new RTO that forms in the west so that the West functions as one seamless wholesale market. A planning work group (PWG) was formed within SSG-WI with the goal to establish a collaborative planning mechanism that functions to coordinate the transmission plans of Western RTOs as if there were a single RTO in the West. The scope includes addressing congestion issues that impact the marketing of energy between RTOs in the West. The PWG is being used as an industry forum to address a number of transmission

[18] WSCC: Minimum Operating Reliability Criteria, revised March 28, 2002

planning concerns in the west in a collaborative manner prior to the formation of RTO West and WestConnect.

Activities of the work group include:

- Continue identification of congested paths previously performed by Western Interconnection Coordination Forum (WICF)
- Identify tools available to evaluate the benefits of projects to expand access to electricity markets and resources.
- Identify and evaluate future solutions to resolve uneconomic congestion.
- Develop strategic development options.
- Address the following "Next Steps" identified in the WGA study:
  - Refine the modeling analysis by:
    - Evaluating alternative growth scenarios that affect implementation of end-use load management, energy efficiency and distributed generation resulting from consumers receiving closer-to-real-time signals on electricity price
    - Expanding the sensitivity analysis to examine the impacts of natural gas prices on electricity prices and load growth
    - Conducting an incremental transmission addition study to better quantify transmission levels and costs
    - Expanding the analysis by including DC transmission options
    - Evaluating the market power mitigation and operational flexibility benefits of either (a) additional generation in transmission constrained area or (b) the addition of more transmission, and
    - Evaluating additional generation scenarios including combinations of wind and peaking resources
  - Evaluate the use of additional emerging technology-based solutions in increasing transfer capability in the existing transmission system such as FACTS controllers.

3.4 WestConnect RTO

WestConnect is an RTO intended to manage the operation of transmission assets in the Southwestern portion of the USA. Its applicants claim to have created an RTO structure that offers flexible participation options for transmission owners with different strategic visions, and that are in different stages of ~~restructuring.~~[20]

~~[20] WestConnect RTO, Docket No. RTO2-000, filed with FERC~~

restructuring.[20] The FERC SMD NOPR will modify Order No. 2000's requirements regarding RTOs, RTO rate design and RTO tariffs. WestConnect, like all RTOs, will have to modify its policies and procedures in accordance with the FERC's Final SMD Rule.

WestConnect filed a petition with the FERC in October 2001 for a declaratory order that it met the elements of being a RTO. To date, the FERC has not acted on the WestConnect ~~business model is founded~~petition. WestConnect is formed as a for-profit entity so that if a transmission owner elects not to build a facility, then WestConnect can build its own.

WestConnect's operational start date is estimated to be early 2006.

The WestConnect planning process consists of (a) developing annual regional transmission expansion plans, (b) following both WECC and NERC reliability standards, and (c) coordinating with WECC to integrate expansions with other facilities in WECC.

A key difference between the individual transmission owners planning processes and WestConnect is that WestConnect is looking at what expansion is needed to support a competitive marketplace throughout the west, and that goes beyond looking at the reliability aspects of the transmission system and whether one can survive a contingency situation or an outage without affecting a neighboring system. WestConnect will incorporate the expansion plans of all transmission owners within WestConnect. That way, WestConnect will be able to avoid duplication of facilities.

The objectives of WestConnect planning are to conform to applicable criteria, meet forecasted demand, identify expansion needed to support competitive wholesale markets, incorporate new generators, and conform to local reliability practices. WestConnect's ten-year plans will identify upgrades, avoid duplication of facilities, ensure reliable and efficient expansion system, encourage robust wholesale markets, and analyze economic alternatives. WestConnect will have responsibility for regional transmission planning, short-term operations and short-term reliability, and will be responsible for managing congestion, calculation of Total Transfer

[20] WestConnect RTO, Docket No. EL02-9-000, filed with FERC

Capability (TTC) and Available Transfer Capability (ATC) and operation of a regional Open Access Same-Time Information System (OASIS), and generator interconnections.

The key functions of WestConnect in so far as it relates to Arizona utilities are:

- Planning and expansion: Provide an open and transparent planning process under the direction and control of WestConnect. WestConnect will have the final responsibility for the regional transmission plan. WestConnect's planning and system expansion process will enable it to provide efficient, reliable and non-discriminatory transmission service, and should encourage market driven operating and investment actions for preventing and relieving congestion.
- Interregional Coordination: WestConnect becomes a member of WECC. WestConnect is participating in an RTO task force formed to address Seams issues and other coordination issues among the three RTOs in the West.

WestConnect will address local utilities' needs only at a transmission level, that is, they have to be related to wholesale transactions.

3.5 Arizona Independent Scheduling Administrator

In contrast with WestConnect, Arizona Independent Scheduling Administrator (Az ISA) is a non-profit corporation, created in 1998 under the laws of the state of Arizona, for the purpose of facilitating the development and function of <u>competitive retail markets</u> in Arizona. Az ISA was created under ACC Rule R14-2-12609 (D), which stipulates that the affected utilities that own and operate Arizona transmission facilities shall form an Az ISA.[21] Az ISA is focused on retail transmission transactions while the regional RTO is focused on wholesale transactions.

The following planning related functions are required of Az ISA, under R14-2-1609 (D) :

- The Az ISA shall implement a transmission planning process that includes all AZ ISA participants and aids in identifying the timing and key characteristics of required reinforcements to Arizona transmission facilities to assure that the future load requirements of all participants will be met.

  The Az ISA Board adopted a staged implementation of its functions based on the extent to which a robust retail market would develop, and the status of Desert Star and WestConnect. As a result of this staged implementation, the planning functions were

[21] AAC R14-2-1609D.05

postponed to Phase II of Az ISA's implementation plans. Important functions such as dispute resolution for those serving the competitive load in Arizona, and monitoring of OASIS functions are included in Phase I of Az ISA's implementation.

- ISA was also to participate in Central Arizona Transmission System (CATS) and Western Area Transmission System (WATS) study groups. ISA's function is to make sure that CATS addresses the retail side and identifies the transmission that would increase the load-serving capability in Arizona.

3.6 Central Arizona Transmission System (CATS) Study Group

Historically, Arizona's Extra High Voltage (EHV) transmission system has been developed to interconnect large generation resources to major load centers located in the Phoenix and Tucson metropolitan areas. The resultant transmission development within Arizona was a system that moved power from the northeastern and northwestern portions of the state to these load centers. The implementation of these practices also resulted in strong ties to neighboring states.

Over the past decade Arizona has experienced substantial growth in the business and residential sectors, particularly in the Phoenix and Tucson metropolitan areas. Structural changes in the electric power market have created tremendous growth in the interest to site merchant generation resources to serve loads both inside and outside of the state of Arizona. The Palo Verde switchyard has become very attractive as a market hub because of the connections to Arizona and California metropolitan load centers and the availability of a nearby gas pipeline.

Subsequent to the 2000 Biennial Transmission Assessment, Salt River Project (SRP), Arizona Public Service (APS) and Tucson Electric Power (TEP) met to discuss how the utilities should move forward to plan for the anticipated growth in transmission capacity needs. In principle, the utilities agreed that a regional transmission planning effort was needed to assess the EHV transmission needs and opportunities in the central Arizona area. Through these joint efforts a Central Arizona Transmission System (CATS) study group was formed.[19] The primary participants included all of the Arizona transmission utilities and Staff. To ensure that the process identified the needs of all stakeholders, invitations to participate were sent to the~~erstwhile~~ Southwest Regional Transmission Association (SWRTA) members, and any other

[19] SRP Ten-Year Plan, 2002-2011, Appendix 1, Report on the Phase 1 Study of the CATS, July 20, 2001

parties that may be interested. Many merchant power plant and transmission developers responded to the invitation.

CATS was created as a forum for open exchange and sharing of ideas. It is a focal point for communications among generators, transmission developers and distribution companies, striving to form a common vision of a long-range regional transmission plan for future development in central Arizona. It has promoted development of joint regional transmission projects benefiting Arizona's retail customers and facilitating market opportunity for an emerging new wholesale power plant industry in Arizona.

The following planning objectives were established by members of the initial CATS study team:

- Improve the use of the existing transmission system for future load growth in the Phoenix and southern Arizona
- Increase the power transfer import level into the Phoenix area
- Increase the power transfer import level into the Tucson area
- Increase the power transfer capability between the Phoenix and Tucson areas
- Encourage future generation additions south of Phoenix and north of Tucson
- Provide additional transmission capacity to and from the Palo Verde hub
- Increase import capability to Phoenix and Tucson from the Coronado/Springerville area where plans for new generation sites are being considered.

This collaborative study forum has also resulted in formation of a subcommittee to investigate future 69 kV through 230 kV high voltage (HV) transmission needs south of Phoenix and north of Tucson. This HV study area involves facilities serving a number of irrigation districts, electric districts, native American tribal lands, and small Arizona communities. CATS participants have also indicated a desire for similar EHV studies to be performed to investigate the California/Arizona transmission interface. The results of CATS' study efforts are described in greater detail in Section 6.

3.7 Evaluation of Planning Processes Active in Arizona

Each utility in the State of Arizona develops its own internal guidelines and criteria to assist in planning its EHV (345kV and above) and HV transmission system. These guidelines and criteria can be found in their entirety in each utility's website (or the utility's study docket).

The planning methods and guidelines are used as the basis for the development of future transmission facilities. Transmission plans are updated on a continuous basis to determine the projected facilities needs for each year over a ten-year period.

The utilities in the state of Arizona plan their system facilities by following WECC and internal reliability criteria, coupled with sound engineering judgment. The utilities plan their system under the (N-1) contingency criteria, and ensure that there are no thermal overloads on lines and equipment, and that the bus voltages stay within normal limits, under normal and emergency conditions.

The utilities perform the required power flow and stability analysis under various system load conditions and (N-1) contingencies, by utilizing the state of the art simulation tools that can represent the bulk transmission system with sufficient detail.

The utilities also are engaged in enormous interconnection study requirements for new power plants, such as the Palo Verde Hub Study.

In addition to planning their transmission systems to meet their internal needs, the utilities in the State actively engage in a coordinated regional planning of transmission facilities in order to ensure (a) that there are no duplicate or redundant facility additions, and (b) that the EHV and HV transmission facilities are planned in the broader context of the needs of the State, and to take advantage of the diverse locations of load centers and generation complexes in the State.

The utilities in the State are also coordinating the planning activities with the utilities in the neighboring states to identify and construct inter-state transmission facilities in order to take advantage of the import and export of competitive energy that would benefit the customers. These planning activities again are performed in accordance with the WECC Reliability Criteria.

APS chaired the WGA transmission study. SRP is chair of CATS, and APS chairs a Western Area Transmission Study (WATS) forum for the Palo Verde and Navajo power plants and transmission providers. WAPA facilitates a joint study with its customers. APS, SRP, TEP and WAPA are participating in the SSG-WI planning group. These are all exemplary planning leadership in the west.

Hence, the planning processes active in Arizona are based on established reliability criteria, and sound engineering practices.

4. Existing Arizona Transmission System

4.1 System Description

The information on existing power plants constructed, owned, and operated by the electric utilities within the State of Arizona, and the existing transmission facilities within the state of Arizona were supplied by APS, SRP, TEP, AEPCO and WAPA in response to a formal request by Staff. Their responses to power plants are summarized in Table 4.1.

Figure 4.1 illustrates the existing EHV and HV transmission facilities in the state of Arizona, and shows the three areas with import constraints.

Table 4.2 depicts the new transmission lines added since the first BTA.

Table 4.3 illustrates the changes in the status of power plants since the first BTA.

4.2 Transmission Paths and Their Ratings

Transmission facilities are rated in a variety of ways. Each transmission line or device has a thermal rating based upon its current carrying capacity measured in amperes. Such ratings are often converted to common power ratings in units of megawatts (MW) or megavolt-amperes (MVA) at nominal system voltage typically measured in kilovolts (kV). Thermal ratings are time dependent and may range from a short time emergency rating to a continuous rating. Such ratings are also dependent upon ambient weather and atmospheric conditions.

A series of devices is generally connected to either end of transmission lines for switching, protective control, voltage control, or metering purposes. The most restrictive device rating in series with the transmission line establishes the thermal rating used for that transmission line.

Table 4.1
Summary of Existing Arizona Power Plants

Plant	Switchyard Voltage (kV)	No. Units	Capacity (MW)*	AZ Utility Capacity (MW)*	AZ Utility Capacity (%)
Agua Fria	230	3	142	142	100.00%
	69	3	407	407	100.00%
Apache	230	2	350	350	100.00%
	115	2	140	140	100.00%
	69	2	30	30	100.00%
Cholla	500	3	995	615	61.81%
	230	1	116	116	100.00%
Coronado	500	2	730	730	100.00%
Four Corners	500	1	740	587	79.32%
	345	1	740	587	79.32%
	230	3	560	560	100.00%
Fairview	69	1	16	16	100.00%
Horse Mesa	115	4	128	128	100.00%
Irvington	138	4	310	310	100.00%
	46	2	162	162	100.00%
Kyrene	230	2	101	101	100.00%
	69	3	163	163	100.00%
Mormon Flat	115	2	58	58	100.00%
Navajo	500	3	2,255	1,522	67.49%
North Loop	46	3	73	73	100.00%
Ocotillo	230	1	54	54	100.00%
	69	3	275	275	100.00%
Palo Verde	500	3	3,810	2,377	62.39%
Roosevelt**	115	1	36	36	100.00%
Saguaro	115	4	313	313	100.00%
San Juan	345	4	1,614	314	19.45%
Santan	230	2	157	157	100.00%
	69	2	156	156	100.00%
Springerville	345	2	800	800	100.00%
Stewart Mountain***	115	1	13	13	100.00%
Yucca	69	5	173	98	56.65%
W. Phoenix	230	3	240	240	100.00%
	69	3	94	94	100.00%
22 Plants Total		**81**	**15,951**	**11,724**	**73.50%**

* Per WSCC Existing Generation Data Base

** Gen tie connected to Fraiser Sub which has two 115 kV lines

*** Gen tie connected to Goldfield Sub having two115 kV lines & two 115/230 kV transformers

Figure 4.1

Table 4.2
New Transmission Lines Added Since the First BTA (To be completed)

Year	Description	Voltage
2001	WhiteTanks-West Phoenix	230 kV
2002	RedHawk-Hassayampa #2	500 kV
2001	Browning Substation	500/230 kV
2002	Satellite Yard/Hassayampa	500 kV
2002	Gila River-Jojoba #1 and #2	500 kV

Table 4.3
Changes in the Status of Plants Since the First Biennial Transmission Assessment

Facility	Estimated Online Date	Output (MW)
West Phoenix (Phase 1)	08/01/2001	120
Desert Basin	06/01/2001	520
Griffith Energy Project	07/01/2001	650
South Point	06/01/2001	540
	Yearly Subtotal	**1,830**
Kyrene	06/01/2002	250
Gila River 1	06/01/2002	520
Arlington Valley 1	08/01/2002	580
West Phoenix (Phase 2)	09/01/2002	500
Redhawk 1	06/01/2002	530
Redhawk 2	06/01/2002	530
Gila River 2	08/01/2002	520
Sundance Energy Project #1	06/01/2002	450
	Yearly Subtotal	**3,880**

The thermal ratings for many existing Arizona transmission lines are listed in Appendix B. These ratings were extracted from a Palo Verde Interconnection Study report.

Another means of rating transmission facilities is by determining the stability limit for a group or set of lines. A stability limit is established via technical studies that determine the maximum power that can be transferred over the group of lines. An electric system is considered stable when excursions in frequency, power and voltage remain within predetermined ranges over time during changing operating conditions or system disturbances.

A grouping or set of transmission lines is often referred to as a transmission path. Transmission paths consist of multiple transmission lines emanating from a common location or between two regions. The performance of each transmission line within a transmission path is interdependent upon the performance of other lines in the same path. The adequacy and security of the whole transmission system is often determined by the performance of key and critical transmission paths.

Transmission lines and paths are also rated in terms of their Total Transfer Capability (TTC). The TTC is the reliability limit of a transmission line or path at any point in time. This rating is established by technical studies that consider the network topology and operational conditions affecting the adequacy and security of the transmission line or path. The thermal rating and the stability limit of transmission lines are both considered when establishing the TTC of transmission facilities. In fact, the WECC has an established process for determining the TTC of major transmission paths in the western interconnection. The transmission path consisting of lines between Arizona and California has the largest TTC of any established path in the Western Interconnection. The map in Figure 4.2 depicts the TTC for key WSCC paths for 2001. This map is slightly different from the map of TTC for 2000 that was included in the first BTA report. For instance, the TTC on the path between Montana and Utah has changed from 600 to 400, and the TTC on the Path from Washington to Montana has changed from 800 to 500, because of changes in system configuration and changes in generation dispatch patterns.

Figure 4.2
TTC for Key WSCC Transmission Paths for 2001

The paths of interest to Arizona are shown in Figure 4.3, and are defined below in Table 4.4. A path of particular interest to Arizona is Path 49, East of Colorado River (EOR). Figure 4.4 illustrates the actual hourly flow on Path 49 during 2001, which shows the flow pattern for the 8760 hours in the year 2001. As can be seen, the flow ranges between 80% and 20% of the paths 7550 MW OTC rating on a daily basis for the year. This is in contrast to the flows reported in the first BTA for the week of December 2-9, 2000, that ranged between 90% and 75% of the path OTC rating.[22] This leads one to conclude that no unforeseen system alert conditions occurred on the western system in 2001, and that the California ISO, which contributed to heavy flows on path 49 during the week of December 2-9, 2000, has taken measures to avoid the recurrence of alert conditions on the California system.

[22] ACC Revised Biennial Transmission Assessment, Docket No. E-00000A-01-0120, July 2001

Figure 4.3

Table 4.4
WSCC Paths in Arizona

WSCC Path #	WSCC Path Name
22	Southwest of Four Corners
23	Four Corners 345/500 kV Qualified Path
49	East of Colorado River (EOR)
50	Cholla - Pinnacle Peak
51	Southern Navajo

Figure 4.4

5. Ten-Year Plans

5.1 2002-2011 Updates Filed January 2002

A.R.S. §40-360.02 states that every organization contemplating construction of any transmission line within the state during any ten-year period shall file a ten-year plan with the commission on or before January 31 of each year. Each plan shall provide:

1. The size and proposed route of any transmission lines proposed to be constructed.
2. The purpose to be served by each proposed transmission line.
3. The estimated date by which each transmission line will be in operation.

A compilation of ~~plannedhtransmission~~planned transmission line additions filed in January 2002 that comprise the Ten-Year Plans for 2002-2011 is provided in Appendix C. The transmission lines are listed both chronologically by projected in-service dates and by the entity that filed the planned addition, and also by transmission voltage level. State statutes require that Staff determine the adequacy of these planned facilities to meet the energy delivery needs of Arizona in a reliable manner. This section of the report documents a review of the ten-year plans filed by the Arizona utilities, and Staff's assessment of how those plans differ from plans addressed in the first BTA.

Figures 5.1 through 5.7 illustrate the planned transmission facilities for the state of Arizona, Phoenix, Tucson, southeastern Arizona, Northern Arizona, Southern Arizona and Mohave County.

Figure 5.3

Figure 5.4

Figure 5.5
Northern Arizona 230 kV Transmission Plans
2002-2011

Figure 5.6
Citizens Transmission Plans
2002-2011

Figure 5.7
Mojave County Area

Tables 5.1 through 5.3 compare the transmission plan filings between the first and second BTA. Based on the information presented by various utilities, the following tables summarize the following:

- Transmission projects filed for the first time
- Transmission projects with change in planned in-service date
- Transmission projects deleted from previous filed plan

Table 5.1
Transmission Projects Filed for the First Time

In-Service	Description	Voltage	Status
2002	Gila River -Jojoba #1 and # 2	500 kV	New
2003	Saguaro-Tortolita #2	500 kV	New
2003	South-Gateway #1 and #2 (Joint Project)	345 kV	New
2003	Gateway-Valencia	115 kV	New
2004	Loop-in of TEP Winchester switchyard (Joint Project)	345 kV	New
2004	Apache-Winchester	230 kV	New
2005	West Wing-Raceway	230 kV	New
2005	East Loop-Northeast through Snyder Phase 2	138 kV	New
2006	Rudd cut in of Jojoba-Kyrene	500 kV	New
2006	Silver King-Southeast Valley # 1 and #2	500 kV	New
2006	Hassayampa-S.E. Valley	500 kV	New
2006	Hassayampa-Jojoba-Mobile	230 kV	New
2006	Flagstaff-Winona	230 kV	New
2006	Browning-Southeast Valley #1 and #2	230 kV	New
2006	Mobile-Southeast	230 kV	New
2006	Pinal-Ice House	115 kV	New
2008	Palo Verde-Table Mesa	500 kV	New
2008	Table Mesa-Raceway	230 kV	New
2008	Fountain Hills Station	115/230 or 500 kV	New
2009	Tortolita-South	345 kV	New
2010	Irvington–East Loop (through 22nd Street) #2	115 kv	New
TBD	Springerville-Greenlee	345 kV	New
TBD	Westwing-South #2	345 kV	New
TBD	Browning-Southeast	230 kV	New
TBD	Vail-East Loop (through Houghton Loop Station) #3	138 kV	New
TBD	Palo Verde-Saguaro	500 kV	New
TBD	Rogers-Browning	230 kV	New

In-Service	Description	Voltage	Status
TBD	Silver King-Browning	230 kV	New
TBD	RS19-RS23	230 kV	New
TBD	Rogers-Corbell	230 kV	New
TBD	Silver King-Knoll-New Hayden	230 kV	New

Table 5.2
Transmission Projects with Change in Planned In-service Date

New In-Service	Description	Voltage	Prior In-Service
2004	Gila Bend-Yuma	230 kV	2006
2006	Santa Rosa-Gila Bend	230 kV	2005
2008	Westwing-El Sol	230 kV	2009
TBD	West Wing-South	345 kV	2006
2009	Loop North Loop-DeMoss Petrie Station through Del Cerro (Sweetwater)	138 kV	2006
2009	Loop Vail-East Loop through Pantano and Los Reales	138 kV	2006
2008	Rancho Vistoso-Catalina	138 kV	2005
2009	Loop Green Valley-Cypress Sierrita through New Cypress Raw Water Substation	138 kV	2007
TBD	Westwing-Pinnacle Peak	230 kV	2012
TBD	Pinnacle Peak-Brandow, Loop into Rodgers	230 kV	2012
2006	Browning-RS19, RS19	230 kV	2012
TBD	RS19-Pierce, Pierce	230 kV	2012
TBD	All SRP Projects	115 kV	2010
TBD	All SRP Projects	115 kV	2012

Table 5.3
Projects Deleted from Previous Plan

In-Service	Description	Voltage	Status
2004	Pinnacle Peak-TS1	230 kV	Replaced with subtransmission facilities
2007	Pioneer-TS5	230 kV	Replaced with Raceway-Avery 230kV
2007	White Tanks-TS3-Buckeye	230 kV	White Tanks-TS3 replaced with Rudd-Lib So-Ts3 and Lib-Lib So-and advanced to 2005
2008	Pinnacle Peak-Pioneer	230 kV	Replaced with Pinnacle Peak –Avery 230kV

In-Service	Description	Voltage	Status
2009	Westwing-Pioneer	230 kV	Replaced with Westwing-Pinnacle Peak, 2011
2003	Loop DeMoss-Petrie-Northwest line through new Fort Lowell-Mountain Substation	138 kV	Deleted

5.2 Technical Studies Supporting Filed Plans

ACC's A.R.S. 40-360.02 stipulates that the ten-year transmission plans be accompanied by a technical study report in support of the plans. The report shall include the power flow and stability analysis performed under various (N-1) contingencies. Through the results of the power flow and stability analyses, the parties shall determine when and where new electrical facilities are needed to serve the customer load in a reliable and economical manner. In addition, the parties shall evaluate, through these study analyses, the needs of increasing the import capability to load constrained areas, and the needs of interconnection of generation to the transmission system to satisfy system adequacy.

All the utilities in Arizona provided detailed technical study reports in support of their ten-year plans, and included adequate details with regard to the contingencies considered, simulation tools employed for the analyses, and the power flow and stability analysis results.

5.3 Forecast of Transmission Siting Applications

The following Table 5.4 is a listing of the projects that will likely file an application for a Certificate of Environmental Compatibility (CEC) within the next two years. It represents a significant hearing work load for the Siting Committee.

Table 5.4

In-Service	Description (CEC Filing Date)	CEC Filing Date	Voltage
2005	Westwing-Raceway	2002	230 kV
2005	Liberty South-TS3	2002	230 kV
2005	Liberty South-Liberty (WAPA)	2002	230 kV
2006	Pinal-Ice House	2002	115 kV
2003	Saguaro-Tortolita	2002	500kV
2006	Trilby Wash-TS2-El Sol	2003	230 kV
2004	Apache-Winchester	2003	230 kV
2006	Hassayampa-SE Valley	TBD	500 kV
2006	Flagstaff-Winona	TBD	230 kV
2006	Gila Bend-Yuma	TBD	230 kV
2008	Fountain Hills Substation	TBD	115/230/345 kV
2006	Silver King-SE Valley #1 and #2	TBD	500 kV
2006	Browning-SE Valley #1 and #2	TBD	230 kV
2005	Loop-in Irvington Station to Vail through Robert Bills-Wilmot substation	TBD	138 kV
2008	Rancho Vistoso-Catalina	TBD	138 kV

6. Arizona EHV Transmission Projects and Studies

There is a need to perform transmission planning and expansion in the State of Arizona at a state and regional level given the location of load pockets, generation resources and merchant plant development. As explained in Section 3, coordination is required among the various transmission providers in developing transmission expansion plans that serve the needs of Arizona customers in an economical and reliable manner. In addition, coordination is required with the utilities in neighboring states to ensure adequate transmission interconnections for import and export of energy. This section describes the coordinated transmission planning activities among utilities in the state of Arizona, and among utilities in the southwest region.

6.1 Diné Power Authority's Navajo Transmission Project

The Navajo Transmission Project (NTP) is a long-distance, long- haul, 460 mile, 500 kV line with an expected capacity of 1,200 to 1,800 MW. It will interconnect Shiprock, Moenkopi and Market Place substations, and traverse three states. The project is being developed by the Dine Power Authority (DPA). The Navajo Nation has the right-of-way, which is 60% of the line from Shiprock to Moenkopi substation.

The ongoing activities on the project development are:

- Finalize combination and selection of NTP segments: Segment 1 from Shiprock to Cheat, segment 2 from Cheat to Moenkopi, and segment 3 from Moenkopi to Southern Nevada.
- Finalize combination of new/existing substations: Substations in Four Corners and Shiprock, and build a new one in Red Mesa East, with 230kV to 500 kV lines coming from the Page area.

DPA obtained a CEC for the non-reservation Segment 3 of the project from the ACC in October 2000. In its decision granting a CEC for the project, the Commission stipulated that construction of Segment 3 could not commence until Segment 1 from Shiprock to Red Mesa was operational at rated capacity.[60] DPA is also required to become a WECC member and file a copy of its Reliability Management Agreement with the Commission.[61] Copies of all interconnection studies performed for the project are also to be filed with the Commission.[62]

DPA identified the following benefits of the NTP:

- Improve the operational flexibility and reliability of the EHV system in the region
- Relieve the constraints on the transmission of electricity west of the Four Corners area
- Allow increased economical power transfers, sales, and purchases in the region
- Improve the economic conditions of the Navajo Nation
- Facilitate the development of Navajo Nation energy resources such as coal, oil, and gas for use in energy projects

6.2 Palo Verde System Constraints

The Palo Verde Nuclear Generating Station is located approximately 35 miles southwest of the Phoenix Metropolitan area. It is comprised of three nuclear generating units with a net output of approximately 1,270 MW each. The Palo Verde Transmission System Facilities include the Palo Verde 500 kV Switchyard, the Arizona Nuclear Power Project (ANPP) Valley Transmission System (the Palo Verde-Westwing 500 kV #1 and #2 transmission lines, the Palo Verde-Kyrene 500 kV transmission line and the Kyrene 500 kV Switchyard), the Palo Verde-Devers 500 kV transmission line, and the Palo Verde-North Gila 500 kV transmission line, as illustrated in Figure 6.1.

Staff raised several issues relative to the Palo Verde Interconnection Study efforts and the siting of all new power plants desiring to interconnect at Palo Verde. The technical studies show that simply interconnecting to a market hub does not assure that the power from new plants can be delivered to the intended consumer market. It further determines that the existing Palo Verde transmission system falls considerably short of being able to accommodate all of the new power plants. According to Palo Verde Interconnection Studies, the existing Palo Verde transmission

[60] Decision 63197, Condition 5, Docket No. L-00000U-00-0103

[61] Ibid, Condition 6

[62] Ibid, Condition 7

system can accommodate a maximum of 3,360 MW of additional power over and above the output of the Palo Verde nuclear units. Generating capacity of the power plants with a Commission approved CEC and proposing to interconnect at Palo Verde or with the Palo Verde Transmission system has a total output (9,595 MW) that far exceeds the limits of the existing system. Therefore, a curtailment procedure must be developed prior to the interconnection of new generation. Staff concludes that the existing Palo Verde transmission system is inadequate given that curtailment procedures will limit the output of the new power plants.

The Palo Verde Interconnection studies do verify that the Palo Verde system is very crucial to the reliable operation of the whole Western Interconnection. This is demonstrated by the voltage stability of the Pacific Northwest being a limiting factor in the outage consideration of some Palo Verde system elements. On this basis, Staff considers the transmission plans for Palo Verde to be inadequate for the interconnection of all new proposed power plants.

Staff began taking a more stringent position regarding the lack of adequate transmission out of the Palo Verde hub in more recent power plant and transmission line siting cases. Staff recommended a moratorium on all pending, or yet to be filed, CEC applications for generating units proposing to interconnect at the Palo Verde hub or with transmission lines emanating from the hub.[63] The moratorium was recommended to allow proper development and review of reliability and system security traits appropriate for large commercial hubs in Arizona and the Western Interconnection, and commensurate with risks present and prevalent in today's society. This need was underscored by the tragic and devastating terrorist attacks against the United States on September 11, 2001.

6.3 Palo Verde Hub Risk Assessment

During the siting process for the Palo Verde/Southwest valley, Staff had concerns about the concentration of lines and generation out of the Palo Verde/Hassayampa site as the hub assumed greater commercial importance.

[63] Staff Exhibit S-1, Docket No. L-00000P-01-0117, September 14, 2001

In the Commission decision authorizing construction of a new 500 kV transmission line from the Palo Verde hub to Southwest Valley (Rudd), APS and SRP are required to "facilitate an industry review and work to achieve consensus with Staff on the reliability and system security measures appropriate for a large commercial hub such as the Palo Verde hub. Such measures shall be recommended to the WECC for consideration and adoption. If and when consensus is achieved between Applicants and Staff, Applicants shall work with Staff to initiate action to implement such measures on a statewide basis independent of WECC action".[64]

A study was initiated by APS and SRP to do a technical analysis in compliance with the aforementioned requirements. The study scope includes a comprehensive technical analysis reviewing a series of catastrophic events and the impact those events could have. Common mode failure events were simulated and various alternatives addressing reconfiguration of the system after such an outage were evaluated.

This unique study first identified causes of catastrophic events including sabotage, weather, natural disasters and equipment failures. Secondly, substation layout and transmission corridors were looked at with respect to these catastrophic events, to see how many facilities would be lost under these common mode events. Computer simulations were analyzed to determine the impact of such events on the system.[51] Preliminary simulation results showed that the system is stable even for these low probability events. However, all the Simulations have not yet been completed. A report will be prepared after all the results, operating and planning solutions have been evaluated.

APS, SRP and Staff have undertaken this study effort in a discretionary manner. In light of the current national anti-terrorism climate it is prudent to err on the side of confidentiality. Once studies are concluded, it may be necessary for the study participants to devise a means of engaging the industry in needed changes without disclosing the details of the study to the public.

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[64] Condition No. 23, Decision No. 64473, Docket No. L-00000D-01-0115

[51] SRP Ten-Year Plan, 2002-2011, Appendix 2, Report on the Preliminary Study for the Palo Verde Interconnection

6.4 Central Arizona Transmission Studies

The CATS study encompasses an area bounded by the Phoenix Metropolitan area to the north, the Tucson Metropolitan area to the south, the Palo Verde Generating Station and environs to the west, and New Mexico to the east as shown in Figure 6.2. The history and objectives of the CATS study group are described in Section 3.6.

The objectives of the CATS study were to develop and address the regional transmission needs of the participants. The study was organized into the following three phases.

Phase I study analyzed individual transmission alternatives proposed by the CATS participants, with the analysis limited to a power flow analysis for (N-0) and (N-1) contingencies. Each alternative was compared to a benchmarked case to determine its performance. The alternatives that performed the best were carried forward into Phase II study.

To meet the original objectives set down by the study team, six transmission paths were determined to be of significant interest in Phase I.

- Palo Verde to Saguaro 500kV line (four variations)
- Palo Verde to Southwest Phoenix Valley 500kV line (two variations)
- Use of Westwing to South 345kV line (two variations)
- 500kV line to the Southeast Phoenix Valley
- Loop-in of the Cholla to Saguaro 500kV line into Silverking (two variations)
- Saguaro to Tucson Area at 500kV, 345kV, or 230kV (four variations).

Power flow studies were performed to assess the system performance of each of the proposed transmission alternatives for each of the generation dispatch and load patterns studied. The study methodology increased generation output in a generation area, and correspondingly increased load in a load area. The system was determined to be constrained when a facility limit was reached for an N-1 contingency. Three major load centers were identified for this study; the Phoenix, Tucson and Southern Arizona load area. The Phoenix load area consisted of load served by both Salt River Project, and Arizona Public Service with the valley load split 55% and 45% respectively. The Southern Arizona area consisted of load served by Tucson Electric Power and AEPCO with the load split 80% and 20% respectively. Four scenarios were defined for study:

- Schedule new generation from the Palo Verde area (Group A. Generation) into the Phoenix area
- Schedule new generation from the Coolidge area (Group B. Generation) into the Phoenix area
- Schedule new generation from Tucson (Group C. Generation), Saguaro and Springerville (Group C. Generation) and Palo Verde (Group A. Generation) into the Tucson and AEPCO areas
- Schedule new generation from the Palo Verde area (Group A. Generation) to the Colorado/New Mexico area.

The study group drew the following conclusions from Phase I study results:

- Building new transmission in the CATS area will increase transfers between Phoenix and Tucson
- While single alternatives can provide benefits to individual participants, more synergies are derived and more regional benefits can be achieved by combining alternatives – that is, regional coordination of transmission planning and development will benefit the entire regional transmission system.
- SRP will derive more benefits from a new transmission alternative between Palo Verde and the Southeast valley (Southeast Station).
  - Phoenix load serving capability
  - Interfacing with the "build out of Browning"
- Tucson will derive more benefits from a transmission alternative between Palo Verde-Saguaro-South or Palo Verde-Saguaro-Winchester
- AEPCO will derive more benefits from a transmission alternative between Palo Verde-Saguaro-Winchester
- The system performance of the Palo Verde-Saguaro and the Gila Bend-Saguaro alternatives is nearly the same. However, the recent establishment of new National Monuments in southeastern Arizona creates uncertainty about being able to build timely transmission for the Gila Bend –Saguaro alternative
- The availability of gas in the Saguaro/Southeast valley area coupled with the proposed CATS transmission alternative to these area should enhance the siting of new generation the Saguaro and Southeast Valley area
- Developing generation in the Saguaro/Southeast Valley area will improve the efficiency of all of the transmission alternatives studied, and increase the load serving capability to Phoenix and Tucson

- Strengthening the interconnection between the Cholla/Saguaro and/or the Coronado/Silverking transmission system to the east of the Phoenix system will enhance exports from Palo Verde to Phoenix
- Developing new interconnections to the transmission system east of Tucson enhances exports from Palo Verde To Tucson
- Opportunities to tie Winchester to the Southeast Valley may improve the capability to the Springerville south system
- The alternatives chosen to advance to Phase II will need to incorporate consideration of TEP's Two–County flow requirements.

The **CATS Phase II** study included power flow analysis of the combination of alternatives found to be most desirable by Phase I study participants. The CATS Phase II base system is depicted in Figure 6.3. The following transmission alternatives to the base system were studied in Phase II:

- Palo Verde to Jojoba 500 kV line
- Palo Verde to Gila Bend 500 kV
- Gila Bend to Watermelon 500 kV
- Watermelon to Mobile 500 kV
- Jojoba to Mobile 500 kV
- Mobile to Southeast Station 500 kV
- Mobile to Saguaro 500 kV
- Southeast Station Loop into Silver King/Browning 500 kV
- Southeast Saguaro to South 500 kV
- Winchester to South 500 kV

The Phase II study scope also included the alternative of replacing one of the 500 kV lines between Jojoba and Mobil and Saguaro with two 345 kV circuits. The loop-in of the Cholla to Saguaro 500 kV line into Silver King with two additional alternatives to the loop-in was also studied.

Several new transmission projects have emerged as a result of the CATS Phase II study effort. Each of the following four projects is depicted on Figure 6.4. The Palo Verde to Southeast Valley 500 kV line has become a formal project. It is being funded by multiple participants and is projected for service in 2006. Secondly, a Winchester Station and related 230 kV transmission project has been identified by Southwest Transmission Cooperative as a requirement for service to its member distribution cooperatives by 2004. The third project is for a 500 kV line between Hassayampa and Jojoba switchyards. Gila Bend Power Partners has filed an application for a CEC to complete construction of that line in 2004. The CATS Phase II study also resulted in the formation of a new HV subcommittee. Its purpose is to study and develop an underlying 69 kV to 230 kV transmission plan for service to northern Pinal County and interconnecting with the CATS EHV facilities.

Based on the results of Phase II study, the following conclusions are reached:

- Both of the Palo Verde to Mobile options, namely, two lines from Jojpoba to Mobile or one 500 kV from Jojoba and one 500 kV from Watermelon had similar performance.
- TEP and Panda Gila River ("PGR") are jointly evaluating a transmission project to connect the Jojoba substation with TEP's West Wing to South transmission line. The proposed transmission project under evaluation would include a new 500 kV line from Jojoba to a new 345/500 kV substation, with the West Wing to South 345 kV line looped through the new 345/500 kV substation.
- Looping Cholla to Saguaro 500 kV into Silver King was a better alternative than looping this line into Southeast Valley. There was little or not benefit looping the Cholla to Saguaro 500 kV line into both Southeast Valley and Silverking.
- There are several good options to strengthen the ties to Saguaro. These options are:
  - A 500 kV line from Mobile to Saguaro.
  - Two 345 kV lines for Mobile to Saguaro.
  - A 500 kV line from Southeast Station to an intermediate switching station (initially named Carpas substation). From Carpas, a 500 kV line connecting to Winchester and another 500 kV line connecting to Saguaro. This can be enhanced with the loop-in of the Cholla to Saguaro 500 kV line into Silver King.

  Each of the above options would require additional facilities to reinforce the remaining Southern Arizona system.
- The development of Winchester substation and a 500 kV line connection from the north reinforces the existing eastern EHV feed into Tucson and Southern Arizona from the east.
- The transfer capability from the Palo Verde Hub and from Central Arizona to the combined Tucson/Mexico area increased with the alternative of one 500 kV line and two 345 kV lines over the CATS base system (two 500 kV lines).
- Additional studies are needed to determine how these alternatives can be staged and integrated.

Based on the CATS Phase II study results and conclusions, the following were identified as **Phase III objectives**, which still needs to be finalized by the CATS Steering Committee.[52]

- Determine the EHV and underlying transmission needed for 2008-2009 time period
- Evaluate Carpas switching station in Southeast Valley station to Winchester line and a tie from this station to Saguaro.
- Determine the need for Mobile station in 2008-2009.
- Evaluate Public Service New Mexico two 345 kV alternative within 2008-2009 CATS system
- Stability Studies
- Determine Phoenix import levels
- Viability of APS Table –Mesa Project
- Develop a ten –year regional plan for central Arizona.

The ongoing Central Arizona HV study between Phoenix and Tucson, and a proposed Arizona - California interstate study project are also being considered by the CATS study group as CATS Phase III progresses.

It is to be emphasized that CATS is an important and significant undertaking. Given its regional scope, the CATS reports were referred by numerous parties in support of their transmission plans filed in January 2002. Similarly, considerable national attention is being given to Arizona's novel and creative approach to planning its transmission system in an open and collaborative manner.

6.5 PNM Arizona-Sonora Mexico Transmission Proposal

The Arizona-Sonora transmission interconnection is a project that Public Service Company of New Mexico (PNM) proposes to connect from Palo Verde to Mexico. The interconnection includes two 345 kV lines running South to the boarder of Arizona, and Mexico, and 60 miles further into the State of Sonora, Mexico connecting to the Comision Federal de Electricidad (CFE) system, as shown in Figure 6.5. The transfer capability of the interconnection is expected to be between 800 MW and 1,000 MW. In order to safeguard against disturbances on either side

[52] Draft Report on the Phase II Study of the Central Arizona Transmission System (CATS), August 16, 2002

of the border an AC/DC/AC converter station will be built on the border. PNM has also been participating in the CATS project. Through this process PNM has identified interconnection opportunities with its project that could improve import capability into the Tucson area by as much as 500 MW.

PNM applied for a Presidential Permit in December 1998, and has been working on the environmental studies. The lead agency for the Environmental Impact Statement (EIS), and Presidential Permit assessment is the Department of Energy. Among other interested federal agencies involved in the process are the Bureau of Land Management (BLM) and Forest Service. Since February of 1999, there have been four sets of public scoping sessions held at 13 different locations in Arizona and New Mexico. The results so far have eliminated five transmission line corridors and now the study is focusing on a remaining five although, in some areas, the preferred corridor has been identified.

The draft EIS is expected to be available for review perhaps as early as September 2002 at which time an application for a CEC will be made to the ACC.

6.6 NRG Proposed Palo Verde/Gila Bend to California Transmission

Generation, existing and under construction, interconnecting to the Palo Verde hub is greater than there is outlet transmission capability to transport. The total nominal generation is around 13,500 MW (4,000 existing and 9,500 permitted), and the transmission outlet capability is 8,500 MW. Hence there is a potential that 5,000 MW of generation would be stranded with an (N-1) planning criteria condition. There is new generation in the Mexicali area that could effectively back off flows from Arizona to California. This would limit Arizona's export to California. There is also new generation proposed for the Las Vegas area which could load the transmission between Arizona and California. Then there is the interaction between transmission and generation, which will stress the existing transmission beyond its capability and reliability. These

Figure 6.5

events could result in stranded generation within the respective generation areas. Increased system losses, wasted fuel, lost income, and higher energy delivery costs with lower reliability could result from the scenarios just described.

NRG has been active in study activities in Arizona and California and offers the following observations:

- Multiple regional study groups such as CATS and WATS are focused on regional areas, with little attention on wider multi-state transmission system.
- Generation companies developed power plant plans without detailed examination of area transmission constraints, including impacts of other area generation.
- New independent power producers have no particular interest in planning adequate outlet transmission for their projects.

The WATTS and CATS study efforts have considered the following possible solutions to Palo Verde area stranded generation:

- Add 500/345 kV phase shifter and a 345kV line from Palo Verde area to Liberty and a third phase shifter at Perkins
- Upgrade existing PV-S. CA 500kV lines
- Add new PV area to Phoenix area Transmission
- Add new PV area to S.CA transmission

The NRG proposes a 500/230 kV project that could add 1,400 MW of transfer capability from the PV/Gila Bend area to southern California area. The NRG proposed project consists of the following elements and is depicted in Figure 6.6

- PV/GB area to Yuma West 500kV (100 Miles)
- Yuma West to Blythe 500kV (60 Miles)
- Yuma West to Highline 230kV double circuit (40 Miles)

There are certain transmission ownership issues such that may inhibit projects such as that proposed by NRG. These include the following:

- IPPs are prohibited by federal law to own and operate transmission
- Low FERC rate of return discourages new merchant transmission and ownership by existing utilities and by Independent transmission owners/operators

- Existing utilities do not have an incentive to build transmission if they are not serving their own load.

NRG has suggested two ways of overcoming such obstacles for transmission projects similar to what they have proposed. First, Public/Private transmission project developments could be formed. As an alternative, IPPs that are building generation in the Palo Verde area could form a consortium to fund WAPA to design, build and operate and Western in return provides firm contractual rights to the use of new transmission capability. Either of these approaches gets around the ownership issue.

6.7 Power Up Corporation's Palo Verde to Devers II Proposal

The sponsor for the Devers II transmission project is Power Up Corporation, a new gas and electric Transmission Corporation. Power Up is in the initial stages of performing feasibility studies to determine siting and constructions requirements for a second transmission line commencing at or near the Harquahala generating station, and traversing westward to the Devers Substation located near Palm Springs, California. This proposal is not being addressed by the CATS study group at the present time.

At the present time Power Up believes that it will co-venture the transmission lines with Southern California Edison. Power Up is reviewing the feasibility of building a gas pipeline along the same route, and stated their preference is to build the transmission line project as a DC link. As an option, there is the notion that the transmission line could replace a project being considered in California by Sempra by expanding the project to reach the Los Angeles basin in Southern California.

Power Up has declared it intends to become active in the CATS, and WATS planning study groups. They intend to file copies of initial feasibility and interconnection studies with the Corporation Commission in late 2002.

6.8 TEP/Panda Gila River Jojoba-Mobile Transmission Project

TEP and ~~Panda Gila River are jointly developing a project to interconnect the Jojoba substation, with which the Panda Gila River project is directly interconnected, to TEP's West Wing to Vail~~PGR are jointly evaluating a transmission project to connect the Jojoba substation with TEP's West Wing to South transmission line. ~~TEP and Panda propose to construct a~~The proposed transmission project under evaluation would include a new 500 kV line from Jojoba to a new ~~substation. The TEP 345 kV~~345/500 kV substation, with the West Wing to South ~~line would then be~~345 kV line looped through the new 345/500 kV substation. ~~The proposed~~This transmission project would improve voltage support in the Tucson area and improve system reliability by providing an additional source of power and by adding an additional path ~~from Palo Verde to~~into West Wing. In addition, the project complements the long-term transmission plans in the region, specifically ~~SRP's~~the proposed South East Valley 500 kV ~~project. TEP and Panda~~project (SEV). TEP and PGR estimate the line would add approximately ~~1200~~600 MW transfer capability ~~when complete.~~into the Tucson area upon completion

7. Local Area Transmission Import Constraints

7.1 Contemporary Challenges Serving Key Load Pockets

Local load pockets are geographic locations in an electric system where the load cannot be served solely by local transmission. During some portion of the year, there is a requirement for local generation located within a load pocket to serve that portion of the local load that cannot be served by local transmission. Such a resource requirement is often referred to as Reliability Must-Run (RMR) generation. That is, areas where loads do not get served totally by transmission, but by a combination of transmission and generation. That combination of facilities establishes what is referred to as the load serving capability of an area. One needs to look at both local generation and transmission capability when assessing the adequacy of the system to reliably serve the load in any load pocket.

The greatest system efficiency is achieved by placing generation as close to the load as practical. This is the benefit of small distributed generation being located at the customer's premises. The same basic benefit is derived from operation of larger central power plants in the local area being served by the utility.

Investment in transmission and distribution infrastructure may be deferred by a utility if such local large-scale generation and distributed generation is reliable, cost competitive with remote power supplies, and is not environmentally challenged or restricted when such units can be operated. On the other hand, a utility must weigh the risks of such local units being unavailable at time of need due to planned or unplanned outages, unavailability or volatile fluctuation of prices of fuel for generation, or changing environmental requirements for generation. Similarly, the utility must consider reserve requirements and development of more cost effective, more environmentally friendly or more reliable resources located remote to the load pocket. Therefore, there needs to be a proper balance between dependence upon local generation and transmission import capability.

The Commission's electric restructuring docket established that local transmission import constraints limit the opportunities for utilities to take full advantage of a competitive wholesale market. Therefore, the Commission ordered APS and TEP to work with Staff to resolve RMR concerns and to publish the resultant plan in the 2004 BTA report. Consideration of the factors listed above is necessary to a proposal.

The first Biennial Transmission Assessment identified three load pockets: Phoenix, Tucson, and Yuma. This assessment identifies two additional import constraint areas: Santa Cruz County and Mojave County. The issues and concerns in each of these five load pockets are discussed below. Figure 7.1 illustrates these five load pockets.

7.2 Phoenix Area Import Assessment

The interconnected EHV and 230 kV transmission system serving the metropolitan Phoenix area is owned and operated by Arizona Public Service Company (APS), SRP and WAPA, as illustrated in Figure 7.2. The Phoenix valley is served by APS' and SRP's 69 kV subtransmission systems and 12 kV distribution systems, with 45% and 55% of the load being served by each utility respectively. Approximately 80% of this load is served by local transmission imports. Load growth occurring in the North and West valley is served by APS and the load growth in the East and South valley is served by SRP.

There are mainly five transmission delivery points into the Phoenix metro area, namely, Westwing Substation, Pinnacle Peak Substation, Kyrene Substation, Browning Substation through Silver King, and the Rudd Substation (previously called Southwest Valley or Estrella) beginning summer 2003, as shown in Figure 7.2. The concern is getting energy into the ring, and internal to the ring there is 230 kV ring around Phoenix.

APS and SRP utilize a combined methodology to develop an annual operating plan that extends forward for several years. It is the most detailed for the current operating season and becomes progressively less detailed for each additional year into the future. The plan models and studies service to loads at voltage levels down to and including 69 kV. The measure of transmission

Figure 7.1

Figure 7.2

import constraint for the Phoenix valley changes over time from solely a wire thermal capability, to a system voltage limit, and then incorporates a MVAR margin requirement to assure stability of the interconnected system.

The APS and SRP operating plan yields a nomogram constructed for use by their System Operators as illustrated in Figure 7.3. The cutset for the nomogram analysis is drawn within the 230 kV ring around the Valley. That nomogram includes a lower boundary referred to as the simultaneous import limit (SIL), a curve representing the projected annual peak Phoenix valley loads at the greatest anticipated temperature, and an upper boundary representing the maximum load-serving capability (MLSC) of the local system. The expected system operation will fall between the two boundaries depending upon load and the on-line local generation. SIL is the simultaneous import limit or wires only capability with no valley generation.

The maximum load serving capability is where one turns on all of the valley generation to their P-Max levels and determines what the maximum load serving capability is.

In 2001, a WECC criterion with regard to voltage constraints, which states that the system must be planned for five percent Var Margin, was applied. This criterion became the most limiting criterion for the Phoenix area and it means that the system should have a five percent Var Margin for (N-0) and (N-1) conditions, and for (N-2) it should have a two and one-half percent Var Margin.

The nomogram depicts the effects of transmission line additions or upgrades on import capability and the voltage constraints while taking into account all the capacitor additions that are shown in Figure 7.3. Through the (N-1) contingency analysis, APS and SRP found the most limiting contingency that drives the Var Margin. It is a Palo Verde to Kyrene 500 kV line outage for which Kyrene 230 kV substation experiences the most severe voltage excursion. The system is manually armed, so that if the voltage dips to below 95%, the load will trip. Figure 7.4 shows the specific projects that are planned, which will add specific values to the SIL and MLSC, for example, in 2002 it is the Ocotillo caps at Kyrene.

Figure 7.3

Figure 7.4

7.2.1 Staff Concerns

In Figure 7.3, which shows SIL and MLSC, SIL has grown in the past two years by 800 MW. This SIL increase resulted from transmission enhancements that allow an additional 800 MW to be delivered into the valley. From 2003 to 2008 SIL increases by another 2,000 MW. Over the same six-year period, Phoenix area load is also projected to grow by approximately 2,000 MW. This implies that APS and SRP SIL are increasing at the same rate that load growth is occurring.

The concern is that the difference between the SIL and MLSC lines (Figure 9.3) appears to be growing over time, and the difference between the SIL and MLSC curves is the local generation. The local generation in this instance is West Phoenix (APS and new Pinnacle West Energy Corp), SRP hydro units on the Verde and Salt Rivers, Santan, Kyrene, Agua Fria, and Ocotillo generation, but does not include Desert Basin and Sundance.

Another concern is that MLSC does not consider any generation outages, but only (N-1) transmission outages. This basically assumes that all of the local generation is running at its maximum and there are no generation outage problems. The outage of the largest unit is not considered. Looking at Figure 7.3, in 2011 there appears to be very little margin, and if the largest unit happens to be out of service, then conceivably MLSC will be below the Load curve. In addition, for **x** hours the valley load is beyond the wires carrying capability.

Also, the utilities operate the local system so that they carry reserves locally to withstand the loss of the largest local unit, which means that the MLSC curve should be lowered by that amount of local reserves.

Looking at the top curve in Figure 7.3, it shows an 11,000 MW import capability in 2003, through four/five major ties and this is the maximum load one can serve with wires and local generation.

The issue that has not been addressed is if local units are modeled at their minimum dispatch level, what would be the transmission import capability—would it exceed the total load requirement or would it be less than the load-serving requirement? Similarly, what combination of local units provides the largest Var Margin improvement when modeled at their minimum dispatch level? Could such improvements be accomplished by additional installation of reactive devices such as capacitors, static or dynamic Var compensators, or new fast acting control devices such as Flexible AC Transmission System (FACTS) controllers.

7.3 Tucson Area Import Assessment

The Tucson area is located in a large valley surrounded by mountains and up until 1969 was served only by local generation. As the load grew, decisions were made to procure resources outside of the area, and bring the power into the area by transmission lines. Imported power now is transmitted from the Westwing substation in the Northwest, from the Saguaro substation through Tortolita in the North, and from Four Corners power station through Springerville in the Northeast. Since transmission lines cannot economically be built in discrete blocks, TEP went through a period before the load grew to match the import capacity. Growth studies indicate that there is sufficient import capacity along with local generation to last until 2008 when some action would need to be taken, as illustrated in Figure 7.5. The transmission system in the TEP area is comprised of 345 kV and 138 kV.

A fairly immediate but small project is a parallel 500kV line between Saguaro and Tortolita substations that will improve import capability by approximately 200 MW. Additional projects include participation, along with Southwest Transmission Coop, on the Winchester Substation which will be built between Vail and Greenlee Substation; a double circuit 345 kV line from South Substation to Nogales with an eventual connection in Mexico to CFE territory; and participation in the Palo Verde to Southeast Valley project.

The import power versus local generation relationship is such that, depending upon which generation is in service, the import capability can be increased anywhere from 190 MW to as much as 300 MW or slightly more.

Tucson's problem from an import constraint point of view is voltage support, that is supporting the voltage locally and running the local generation to alleviate that problem.

Figure 7.5 shows TEP's maximum transmission import capability for its Tucson service area is presently 1,538 MW and increases to 1,690 MW with the addition of a second Saguaro to Tortilito 500 kV tie in 2003. This transmission import capability relies upon local generation being operational at maximum dispatch levels. The MLSC of the TEP service area ranges from 2,178 MW in 2002 to 2,430 MW in 2010. The issue is whether to build additional transmission or to build more local generation beginning in 2008. TEP indicates that local peaking units have historically been most economical and hence, two local peaking units of 75 MW each are assumed for 2008 and 2010. The TEP/Panda Gila River 500 kV transmission project under evaluation would add additional import capability from Jojoba or Palo Verde to TEP's system.

Figure 7.6 shows transmission import capability dependency versus local generation in 2002. With no local generation, 950 MW of load can be served with import capability.

Staff concerns:

A point of contention is (looking at Figure 7.6), for 11 MW of local generation on-line, import capability increases from 950MW to 1,239MW. With Irvington units 1 and 4 on at a minimum dispatch of 11 MW, TEP can import 1439 MW via its transmission system. That means that TEP's import transmission capability is very sensitive to which units get committed locally. The WECC criteria with regard to Megavar margin are followed. However, all the other measures including adding capacitors are considered before adding more local generation. The most feasible and yet lowest cost solution is chosen.

Looking at the load duration curve, Figure 7.7, for 4,300 hours of the year, no local generation is required from an import perspective, and then add incrementally in small quantities to get the import capability needed.

In 2003, must run generation at 180 Gigawatt hours is estimated, and 80% of that occurs in four summer months.

7.4 Yuma Area Import Assessment

Peak load in the Yuma area is expected to grow from about 300 MW in 2002 to about 375 MW in 2006. This load is served by a combination of local generation and imported power. The local generation consists of two 19 MW and two 55 MW combustion turbines, three of which are capable of burning oil or gas, and the fourth is oil only. The line capacity is made up of 38 MW on Western's 161 kV Parker-Yuma line, which is APS 11 % share, 40 MW of the Palo Verde-North Gila 500 kV transmission line plus short term purchases from San Diego Gas and Electric Company, which owns the largest portion of the Palo Verde-North Gila 500 kV line along with power purchases from CAISO. This basket of resources will provide capability to serve loads up to 375 MW.

APS filed plans that propose to build a 230 kV line from Gila Bend to Yuma by 2006, which will add 150 MW of transfer capability to meet the area load serving needs. APS is also looking at a list of options and alternatives that includes other transmission and local generation solutions. These include making modifications to the Palo Verde-North Gila line which will give APS about 40 MW more import capability by eliminating sag limitations, improving series capacitor ratings, and reducing induced voltage into the communications system used by a railroad. System upgrades at Blythe can also help the Yuma area. There are literally a handful of other options that taken together can add to APS' ability to serve load in the Yuma area.

In summary, it appears that the measures contemplated by APS should be able to alleviate the import constraints in the Yuma load pocket.

7.5 Santa Cruz County Import Assessment

All the power purchases are coming from Pinnacle West and delivered through two points of receipt on the Western system. The largest majority of load is delivered at Pinnacle Peak.

At the present time the load in the Santa Cruz County area, Nogales in particular, is served by a single 115 kV line operated by Western. Citizens has generation located in the Nogales area that it runs on an emergency basis. When the single 115kV line is out of service, the local generation is used to pick up the Nogales load. During storm seasons, the local generation is started, but not brought on line until after a power outage occurs.

In order to improve the reliability of service in the Santa Cruz County area, Citizens has developed an agreement with Tucson to connect to Tucson's Suguaro substation by way of a 345 kV line that will terminate at a new substation, Gateway, located about 3 miles from the Valencia substation near Nogales, as shown in Figure 7.8.

A short 115 kV line will be built to connect to Suguaro from the Valencia substation near Nogales. 115 kV capacitors will be installed at Valencia to improve voltage during transmission outages.

The 345 kV line will add 100 MW of firm capacity to the area, which is currently limited to 69 MW. Citizens will be working with Western and with Southwest Transmission Coop that also has customers in this area to see if some or all of the difference could be made up.

7.5.1 Issues and Concerns

With a 50 MW peaking generation at Valencia, if a transmission line goes out of service, then load can be picked up by starting this generation. During monsoons, Citizens separate Nogales City from the rest of the system in Santa Cruz County and run Nogales turbines, since the small units are not capable of remaining in synchronism with the rest of the system. So, a small part of the load is isolated on local generation.

Figure 7.8
Santa Cruz County

The hours that the Santa Cruz County load would exceed the 69kV line capacity--. The number of hours that the load would exceed 70 MW (peak load) is not greater than 9.

Three-year contract with Western maxes out at 69 MW.

If there is a Western preference customer, it will be shipped from Saguaro toward East, and western customers would get the preference.

7.6 Mojave County Import Assessment

The Mojave load area includes the Peacock, Parker, and the Davis areas, encompassing the cities of Kingman, Havasu, and Bullhead, and is in part served by Citizens Communications Company, Arizona Division, and by Mojave Electric Coop, as shown in Figure 7.9. Southwestern Transmission Cooperative, Inc. and Western provide transmission service.

Western's path D, Phoenix to the river, is made up of three lines. These lines run from Liberty to Parker, and from Pinnacle Peak to Davis, and then to Kingman and Lake Havasu. This path is contracted for completely.

The load growth in the Lake Havasu City area had necessitated Citizens to build another substation, North Havasu, and an associated 230 kV transmission line, Griffith/North Havasu.

Near term with maximum generation at Griffith (merchant plant), Davis, Parker and Southpoint backed down and the Havasu pump at full operation, there are problems relating to (N-1) conditions. Parker generation being brought up could alleviate the problem, but there is a quandary with lack of water to run the plant.

The merchant plants that operate within the area are in the Western control area, and could be expected to operate to reduce the constraints, but there is no process by which payment could be after the fact. It is possible in the future that the merchant plants will not be included within the control area which further complicates the relationships.

Figure 7.9
Mojave County Area

There are some options being discussed by the transmission providers, and service utilities, but no concrete study has been undertaken to determine what should or can be done. Further, there does not seem to be an entity such as CATS, that could perform such a study. Meanwhile, Citizens continues with their 3-year rolling term contracts for transmission service with Western, and at the same time merchant plants, such as Griffith, continue to press Western for long-term transmission service.

One of the alternatives to import power into the Mojave County area is to come from Mead to McCullough area.

Another alternative is how the local generation is factored into the deliverability of transmission. It is being completely separated partly because of FERC rules with respect to interconnection. There is generation sitting in the middle of a load area but it is not functioning to support the system to meet the load. So, this is another transmission import constrained area.

Also, based on system situations, these merchant plants can be treated, as reliability must run generation.

7.7 Reliability Must-Run Generation (RMR) Requirements

(This section is yet to be developed with input from transmission providers.)

8. Local Area Transmission Plan Assessment

8.1 General

The Western Area Power Administration (WAPA or Western) operates over 3,000 miles of transmission lines that connect from generally Northwest to Southeast within the Desert Southwest Region. This transmission system was built to meet the needs of 81 long-term preference customers. Western does not have any load of its own, and consequently has a policy not to build transmission for new load of others. Western follows NERC and WECC standards for reliability; and in practice, offers its services on first come first served basis after meeting the needs of its preference customers. These services can be obtained by contracting for excess line capacity, or by paying (establishing a trust account) for the service. During Western's continuing efforts in maintaining plant interconnections, system improvements that do not cost more than the routine maintenance are accomplished. This practice adds small amounts of capacity to some paths over time.

Western has almost all of its capacity engaged in long-term contracts. Small amounts of short-term capacity are available on a limited number of paths, but no large amounts for the long term are available.

The following three local areas are expected to experience transmission constraints as shown in Figure 8.1:

- Central Arizona
- Northern Arizona
- Southeastern Arizona

8.2 Central Arizona

There is load growth in the Central Arizona area, and there is not enough transmission to serve the customers in that area. CATs efforts came up with a nice 500 kV overlay between

Figure 8.1

Phoenix and Tucson, but did not look at the underlying 230/115 kV system that is serving the customers. The Arizona Power Authority is looking into that underlying system, and it is a big effort that is just getting underway. The transmission resources are planned to be developed for 2006-2007 time frames.

The initial system to be studied extended from Palo Verde to Southeast valley. Another region to be modeled is the Casa Grande, Maricopa area. Looping in the Sundance/Liberty line out of Lone Butte, and also the Westwing/Liberty line into the Rudd substation will be looked at as alternatives. In addition, the Santa Rosa to Gila Bend line will also be looked at. There are some difficulties in the region, and the study efforts are to look at how to overcome those difficulties with regard to line capacities.

The study is just getting started and hence, there is not much to report by way of analysis results or problem areas.

8.3 Northern Arizona

The local transmission system in Northern Arizona will be unable to serve the projected loads after 2006. The area included Prescott to the west, Holbrook to the east, and Flagstaff in the middle, as shown in Figure 8.2. There is not enough transmission to serve the load that is growing in that area. There is an existing 345 kV WAPA line from Glen canyon to Pinnacle Peak. A proposal would have Western add a 345/230 kV transformer at Flagstaff, and build a 230 kV line from Flagstaff to Winona area. The Winona substation in the Flagstaff area will need additional support by that date. APS and Western have had preliminary discussions centered on a possible joint effort to resolve the load issue.

From Western's perspective, the path from Phoenix to the River is fully subscribed, that is, Western's path D, which consists of two lines from Liberty to Parker, and a line from Pinnacle Peak to Davis.

Figure 8.2
Northern Arizona Area

Western's line from Pinnacle Peak to Prescott in interconnected to APS system at Willow Lake, which might cut own losses.

To date no concrete process has been established to move forward on a solution.

8.4 Southeastern Area

8.4.1 Southwest Transmission Cooperative

The Southwest Transmission Cooperative's (SWTC) existing backbone transmission system consists of two 230 kV lines that exit Apache Station going east and west. The 230 kV lines interconnect to TEP at Greenlee Substation to the east and Vail Substation to the west. SWTC also owns a 115 kV line that emanates from Apache Station and goes north to interconnect with Salt River Project (SRP) at Hayden Substation. Western owns a 115 kV line that also exits Apache Station and goes west, as shown in Figure 8.3.

On the current SWT Coop transmission system, the most severe single element outage is the loss of the Apache to Redtail 230 kV line. During this 230 kV line outage, the 345/230 kV transformer at Bicknell Substation and the remaining 230 kV line become heavily loaded.

To meet WECC's reliability criteria to be able to withstand any single element outage without uncontrolled loss of load, (N-1), and to avoid cascading outages by shedding and/or reducing generation (N-2), SWTC studied several alternatives.

The Winchester Interconnection Project has been developed as part of the efforts by SWTC to enhance the reliability of the SWTC transmission system. It provides an additional 230 kV line that exits the existing Apache Station to a new interconnection point with TEP's 345 kV line from Greenlee to Vail. This project reduces the overload on system segments for (N-1) conditions, and decreases the need for Remedial Action Scheme (RAS) during multiple contingencies.

Figure 8.3

Joint projects with APS in the area are contemplated. Sulphur Springs Valley Electric Cooperative is planning a substation in the Palominas area that could help to serve the APS load in the area.

8.4.2 Citizens Utility

At the present time the load in the Santa Cruz County area, Nogales in particular, is served by a single 115 kV line operated by Western. Citizens has generation located in the Nogales area that it runs on an emergency basis. When the single 115kV is out of service the local generation is used to pickup the load. During storm seasons, the local generation is started, but not brought on line until after a power outage occurs.

Citizens has developed an agreement with Tucson to connect to Tucson's Suguaro substation by way of a 345 kV line that will terminate at a new substation, Gateway, located about 3 miles from the Valencia substation near Nogales, as shown in Figure 8.4.

The 345 kV line will add 100 MW of firm capacity to the area, which is currently limited to 69 MW. Citizens will be working with Western and with Southwest Transmission Coop that also has customers in this area to see if some or all of the shortfall could be made up.

Citizens has filed a report with the ACC relative to the improvements of the existing line from Nogales down to the Citizens service area, by adding capacitors to withstand the outage of the new line to Nogales.

The Western line that is delivering power into Citizens system becomes a constraint as the Citizen load grows. When a second line into Nogales is completed, Citizens will have 100 MW of transmission capacity from Saguaro to Nogales. To improve the load carrying capability, Citizens is adding Var capacity of 50 Mvars on the system.

Figure 8.4

Eventually, there is a need to develop at least 100 Mvar carrying capacity, in the 2004-2005 time frame.

8.4.3 Tucson Electric Power

TEP's 138 kV system is totally contained within the TEP service area. TEP set up a separate tariff rate for 138kV system. There are no constraints in the 138 kV system, since the system was designed and built to eliminate all local internal constraints. TEP continues to upgrade the 138 kV system by using SSAC conductor for added current carrying capability. A 138kV line at the southern edge of TEP service area connects down to Green Valley, south of Tucson, which is a retirement community. That line is going to be continued to make a loop, with an in-service date of 2005. Hence the action items needed are reconductoring and upgrading existing 138 kV lines, and thus there are no internal constraints at the present time.

9. Merchant Plant Update

9.1 Ten-Year Plans

A.R.S. 40-360.02 states that every organization contemplating construction of any transmission line within the state during any ten-year period shall file a ten-year plan with the Commission on or before January 31 of each year. This requirement applies to merchant plants as well as those that are planning interconnections with the Arizona transmission grid. The merchant plants shall demonstrate the impact of transmission interconnections on the transmission grid through power flow and stability analysis results.

A compilation of planned plant interconnections filed by merchant plant developers in January 2002 is included in Appendix C. This section of the report documents a review of the ten-year plans filed by merchant plants, and Staff's assessment of those plans.

9.1.1 Gila Bend Power Project

Gila Bend Power Partners (GBPP) plan to build a 500 kV and a 230kV line as part of the project. The size of GBPP is expected to be 833 MW.

As shown in Figure 9.1, the 500 kV line will run from the GBPP site in the Northwest corner of Gila Bend and interconnect with the APS Gila River line at the Watermelon switchyard. The 230kV line will run from the GBPP to the APS Gila Bend substation at which point it will be interconnected with the APS Gila Bend to Liberty 230 kV line.

The 500 kV system impact study is completed and the 230 kV impact study is ongoing.

The 230 kV and 500 kV lines and the Watermelon switchyard are scheduled for completion in late 2003.

Figure 9.1

The purpose of the system impact study was to assess the impact of GBPP project on the Palo Verde transmission grid and the WECC EHV grid. The study was limited to power flow and stability analysis. The study results are included in reference #40. For this analysis, two alternative configurations were evaluated: (a) GBPP project interconnection to the planned Jojoba-Gila River 500 kV double circuit line at Watermelon station. This assumes a 500/230 kV transformer at Gila River substation to interconnect the existing Liberty-Gila Bend 230 kV line, and (b) Same as (a), without the 500/230 kV transformer at Gila River 500 kV substation.

The study result of significance is that the maximum generation that can be scheduled out of Gila River vicinity to Arizona load centers is a function of the capability of Palo Verde transmission, which is based on the thermal limitation of either the Hassayampa –N. Gila 500n kV line or the Hassayampa-Kyrene 500 kV line.

The maximum GBPP generation that can be scheduled is 583 MW with Configuration (a), and 683 MW with Configuration (b). With these schedules, the GBPP interconnection will not have any adverse impact on the Palo Verde plant, and its grid.

9.1.2 Gila River ~~Project~~Power Station

~~Panda~~The Gila River Project is a generating project owned by Panda Gila River ~~LP.~~LP, ("PGR") It will consist of four ~~2X1~~2x1 gas fired combined cycle power blocks for a combined nominal rating of 2,080 MW. Operation of the first unit is scheduled to begin April 2003, with the last power block in service August 2003.

The ~~power flow and stability analysis showed that the existing system can support only up to 500 MW of non-firm with three separate special protection schemes, and without any protection schemes, APS can provide only 106 MW of firm transmission over the existing system. These results illustrate that the Gila River project will require significant transmission additions to interconnect the entire 2,080 MW output from the plant. Hence, several alternative plans were considered.~~

~~The project will interconnect with both the 500 kV and 230 kV systems. Two 500 kV lines have been built to Jojoba, a new substation, that will be connected to the Palo Verde-Kyrene 500 kV line. The 230 kV tie will be to the Liberty-Gila Bend line, as shown in Figure 9.2.~~ Gila River Project will have three interconnections: two with the 500 kV system and one with the 230 kV system. Gila River will interconnect with the ANPP Valley Transmission System Palo Verde-Kyrene line through two 21 mile long 500 kV transmission lines at the newly constructed Jojoba substation scheduled to be in service by November 1, 2002. The third interconnection will be a 230 kV tie to the Liberty-Gila Bend linethrough a new 230 kV substation, as shown in Figure 9.2.

Gila River's interconnection at the Jojoba substation provides significant stability benefits over an interconnection at Palo Verde/Hassayampa. With the Palo Verde to Jojoba 500 kV line segment out-of-service, PGR can reliably deliver at least 1,800 MW to Kyrene via the Jojoba to Kyrene 500 kV path and 240 MW to Liberty via the Panda to Liberty 230 kV path. For this outage, PGR is the only generator in the region that can directly deliver power at Kyrene, improving system reliability. With the Jojoba to Kyrene 500 kV line segment out-of-service, PGR can reliably deliver at least 1,600 MW to Palo Verde via the Jojoba to Palo Verde 500 kV path and 430 MW to Liberty via the Panda to Liberty 230 kV path. With the Liberty to Panda 230 kV line segment out-of-service, PGR can serve APS load at Gila Bend. With the two 500 kV lines from Palo Verde to West Wing out-of-service, PGR can reliably deliver at least 1825 MW on the 500 kV system and 300 MW to Liberty via the Panda to Liberty 230 kV path.

~~The project has been actively working with CATS developinginterconnection options. The power station~~The Gila River Project currently has 333 MW of firm transmission service to ~~Jojoba and on into the Palo Verde hub. APS has offered 430 MW to Liberty on the 230 kV lines.~~the Palo Verde hub from APS. APS has offered an additional 430 MW on the Gila River to Liberty 230 kV line. The Gila River Project has made transmission service requests from SRP for 1100 MW on the Jojoba to Palo Verde line. Also, under consideration ~~are 600 MW on the Kyrene line, and~~on the Jojoba to Palo Verde line is 196 MW from El Paso Electric. ~~Further discussions are being held with APS for 1,100 MW of an available 1,500 MW from Jojoba to Palo Verde. Also being explored is the possibility of utilizing some transmission network~~

~~resources, but there is not any OATT precedence to do that. Other options including building from Jojoba~~

~~east and constructing a 500 kV to 345 kV station and looping Tucson Electric Power's Westwing to Vail line.~~

The Gila River Project has also asked to be studied by APS as a network resource on their system. AlthoughAPS claims there is no OATT precedence to perform such an analysis, there is no technical reason this analysis cannot be performed. Furthermore, the FERC appears to be moving toward a requirement that transmission owners study *all* generation as network resources and that the transmission owners expand the definition of network service. *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,451, FERC Stats. & Regs. ¶32,563 (2002) at ¶ 152 (creating Network Access Transmission Service and proposing to eliminate the requirement that network customers designate network resources); *AEP Power Marketing, Inc., et al.*, 97 FERC ¶ 61,219 (2001)(requiring AEP, Entergy and Southern Company to model interconnecting generators as if they were serving load within the control area without designation of specific load).

The Gila River Project has been actively working with CATS developing additional interconnection options, including an interconnection with Tucson Electric Power's 345 kV Westwing to Vail line. TEP has filed an interconnection request with the ANPP Valley Transmission System to interconnect, via a 500 kV transmission line, a new Pinal West 500/345 kV substation to the Jojoba substation. The Pinal West 500/345 kV substation would have TEP's Weswing to Vail 345 kV line looped through, providing a direct path from Jojoba to TEP's system. This interconnection request is being evaluated by SRP as the first phase of the SEV project which is currently in the siting and permitting process. In summary, to ensure access to the Palo Verde trading hub, the project has secured 333 MW of firm transmission service from APS, requested 1100 MW of service from SRP, and is considering 196 MW from El Paso Electric. In addition, PGR is evaluating a joint transmission project with TEP for up to 600 MW of service on the Westwing-Vail line. The combination of Gila River's interconnection to both 500 and 230 kV systems provides the project with ample transmission access to deliver the full output of the Gila River Project to market and improves the overall reliability of the Arizona ~~The bottom line is that it appears that the best two alternatives may be requesting a facility study to determine what the costs of the above alternates would be to obtain service; the other would be to build transmission from Jojoba up into Rudd (Southwest Phoenix).~~transmission system.

9.1.3 Sundance Energy Project

The Sundance project with a total gross generation of 450 MW in stage I, has requested for transmission service. This includes interconnection to Desert Southwest Region (DSW) system extending from the Coolidge area to greater Phoenix area, as shown in Figure 9.3.

The Stage I system impact study was conducted according to Western's OATT, and looked at the transmission upgrades needed to mitigate any impacted DSW facilities, and the impact of the Project on the stable operation of the interconnected system. The study results showed that there are no power flow and stability problems, and no equipment overload problems.

Figure 9.2

Figure 9.3

9.1.4 Ambos Nogales Generation Project

The plant capacity is estimated to be 500 MW, combined cycle natural gas fired facility, with a 230 kV double circuit line connected to CFE in Mexico (and not connected to the US grid), and a 115 kV intertie with Citizens. The project is expected to start construction by 2003, and be in operation by 2006, assuming CFE approval.

No power flow and stability analysis has been performed since it is not connected to the U.S. grid, and since no capacity is proposed to be exported out of Citizen's service area.

9.1.5 Reliant Energy Signal Peak Project

The Signal Peak Power Project is planned to interconnect power plant in Casa Grande, AZ with the Phoenix Metro transmission system. One 230 kV circuit is planned to terminate at Knox substation, and the other 230 kV circuit would terminate at the Schrader substation.

CEC application has yet to be filed and the system impact studies have yet to be completed.

9.1.6 Allegheny Power Project

Allegheny Power project plans to interconnect a new generation plant with a capacity of 1,290 MW to SCE's Devers-Palo Verde 500 kV line. The proposed in-service date is 2004.

The system impact studies revealed that the existing facilities are inadequate to accommodate the Allegheny power project. The Allegheny –Devers and Palo Verde-North Gila 500 kV lines are loaded in excess of the ratings as limited by capacitors. The Allegheny power project will be required to schedule according to SCIT nomogram and will have an adverse impact on the amount of EOR and WOR generation that can be scheduled for import.

A facilities study is required to determine the facilities and upgrades required to interconnect the proposed project.

9.2 Operational Experience of Plants On-Line

During the presentations several questions were asked of the panel members, which lead to discussions. The discussion points, and responses are captured here even if there was not a full conclusion arrived at:

- Did the plant owners believe they had performed adequate interconnection studies, either themselves, or in collaboration with the transmission providers, to determine the impact of their power plants on the integrated grid system, either current operation or future operation? The respondents believed that considerable study had been performed. In the cases of the operating plants there have not been any difficulties in operations due to transmission constraints except as noted by specific plants.
- What and who determines the commercial operation date? The date that the plant is operational has mainly to do with warranties, and provisional performance acceptance as described in the construction contracts.
- A further discussion developed about whether or not the merchant plants were to participate in supplying area reserves. It was not clear that the respondents fully understood the premise of the question, but most agreed that their plant was to help out the system in some way.

9.2.1 South Point

South Point is a generating station owned by Calpine Western Region. It consists of a combined cycle 2X1 gas fired plant producing 550 MW. The project came on line in May 2001, and up until December 31, 2001 had achieved 5580 hours of operation. This year through June, the plant has experienced 380 hours of planned outage.

The plant is connected to South Point substation, near Topock on the Parker-Davis line. Firm transmission exist for delivery to five points; Mead, Pinnacle Peak, McCullough, Marketplace and Liberty, with terms of 40 years. Transwestern supplies gas.

The plant has not experienced any delivery constraints.

9.2.2 Griffith Energy

Griffith Energy is a generating project owned equally by Duke Energy and PPL. It consists of a combined cycle 2X1 gas fired plant producing 600 MW. The project was declared commercial on January 17, 2002, and has run at an average of 40 percent capacity factor since going commercial, limited by market conditions.

The power project has firm transmission to Mead provided by Western, and is sited in Westerns control area. In constructing the plant, a new substation, Topock, was built along with 28 miles of new and 60 miles of reconductored 230 kV line. Topock substation connects the plant to Westerns 345 kV Davis to Prescott line.

Although the plant is located in Mojave County, a transmission constrained area, the plant output flows out, not in, and does not contribute to the constrained problem.

9.2.3 West Phoenix 4

West Phoenix 4 is owned and operated by Pinnacle Peak West Energy Corporation. The plant is a 1X1 utilizing a stress demand steam turbine with supplemental duct firing. It went into service in June 2001, and has to date experienced an annual capacity factor of 60 percent, and an availability factor of 90 percent. The plant is fueled with gas from the El Paso pipeline.

The plant is constructed on the site of an existing power station that contains three other plants. The site has infrastructure built in anticipation of West Phoenix 5. An initial interconnection study was performed and as a result some reconductoring of 69 kV lines was done to accommodate the plant. In the future some reconductoring and building of 230 kV lines is anticipated, including a line to White Tanks, as well as installing refrigeration on a 230 kV Cable, Lincoln -Country Club.

The plant serves Arizona load, and there has been no restricted operation due to transmission constraints.

9.2.4 Desert Basin

Desert Basin is a generating project owned by Reliant Energy. It consists of a combined cycle 2X1 gas fired plant producing a nominal 500 MW, and is supplied by the El Paso gas pipeline. The plant was declared commercial in October 2001, and has run at an average capacity factor of 65 percent, and an availability factor of 90 percent. The full output has been contracted to SRP.

Like other power projects, the owner worked with the transmission provider to identify constraints. There are system conditions that can occur that would preclude the plant from operating at full output, and corrective actions have to be implemented. However, Reliant claims that Desert Basin has operated successfully with no reductions or curtailments below 510 MW of firm point-to-point transmission service from APS. However, it is to be noted that the total output of the plant is 560 MW as per the approved CEC. That means that there might be transmission adequacy problem if the balance of power from the plant were to be delivered to any entity other than SRP.

It is to be noted that the current operating procedures in the vicinity of the Desert Basin plant allow the plant to deliver only 510 MW of firm capacity under the Transmission Service Agreement (TSA) with APS. But, under certain conditions, with the loss of the Desert Basin to Santa Rosa 230 kV line, corrective actions have to be taken within 30 minutes of the outage to relieve overloads of the grid. These corrective actions range from a reduction in the output of about 50 MW of either Desert Basin or Saguaro.

9.3 Project Status of Plants Scheduled for Future Years Operation

9.3.1 Mesquite

Mesquite is a generating project developed by Sempra Energy Resources. The plant will consist two combined cycle 2X1 gas fired plants producing 1,000 MW. The first power block is scheduled to be in service on June 1, 2003, the second block in November of 2003. Engineering, purchasing, and construction are ahead of schedule at this point. El Paso Gas will furnish the gas through a pipeline connection that includes plants owned by Pinnacle West, Redhawk 1 & 2, and Duke, ARVL 1.

The transmission connection is to Hassayampa where the Mesquite shares a property boundary. The Hassayampa switchyard study included connection of the plant.

9.3.2 Santan

Santan is a generating project owned by Salt River Project. It will consist of one 2X1 and one 1X1 combined cycle units for a total of 825 MW. Santan is an existing generation station, which currently has four combined cycle units with a combined output of approximating 400 MW, built in the mid 1970's. El Paso Gas supplies the station with fuel, and for this plant the cooling water supply will be a combination of effluent from the town of Gilbert, and water from CAP. The gas pipeline capacity is limited so SRP is in the initial stage of developing a 40-mile pipeline extension from south of Coolidge.

A 230 kV and 69 kV substation exists at the station.

Anticipated commercial operation date is May 2005

9.3.3 Harquahala

Harquahala is a generation station owned by PG&E National Energy Group. The stations will consist of three 1X1 power blocks. All of the units are expected to be in operation by summer 2003.

Harquahala was included in the Hassayampa interconnect study, and no transmissions problems are expected. However, the plant rating has been increased to 1,170 MW, which puts an additional burden on the transmission system that is already constrained.

9.3.4 Bowie Power Station

Bowie is a generating station that is owned by Southwestern Power Group, and will be located one and a half miles north of the town of Bowie, AZ. The station will consist of two combined cycle 2X1 power blocks each producing 500 MW. The first power block is expected to be placed in service 4th quarter 2004, and the second block in service 4th quarter 2005. A Certificate of Environmental Compliance was awarded in February 2002. Additional permits that are being worked on include an aquifer protection permit for the cooling ponds, and a rezoning permit. There are four optional pipelines that can be connected to, but the most likely is the El Paso Natural Gas All America pipeline, that is anticipated to be in service at 800 psi in fall 2002, although a 404 permit will be required. All of the permits are expected to be in hand by fall 2002.

An interconnection study is being conducted by TEP with expected results early fall 2002, followed by a facility study which will lead to entering into an interconnection agreement by January 2003.

9.3.5 Desert Energy

Desert Energy will be a gas fired combined cycle plant rated at 585 MW, and will be located near APS' Saguaro station. The owners expect to be in siting hearing by early 2003. This workshop is the first public announcement of the power station, and consequently many of the studies, and applications are just starting to be filed. Consequently no interconnection study has been performed.

9.3.6 Phoenix West

West Phoenix 5 is a generating project owned by Pinnacle West Energy, and is located at the existing West Phoenix station. It consists of two combined cycle 2X1 gas fired power blocks each producing 530 MW. The project is on or slightly ahead of schedule, which would put it in service by June 2003.

In conjunction with the West Phoenix station expansion upgrades were made to the switchyard, and to the transmission line connections to accommodate the project. No transmission line constraints are anticipated.

9.3.7 Redhawk 3 & 4

Redhawk 3 & 4 will be an expansion of an existing power station owned by Pinnacle West Energy. It will consist of two power blocks, with a footprint similar to Redhawk 1 & 2. Each power block will produce 530 MW.

The plant has an approved CEC, and air quality permit in hand. When Redhawk 1 and 2 were constructed some infrastructure was built in anticipation of Units 3 and 4.

In service date either 2006, or 2007.

9.3.8 Wellton-Mohawk

The Wellton-Mohawk station will be a combined cycle generating station consisting of two 2X1 power blocks each producing 310 MW. Wellton-Mohawk operates a distribution system with a load of about 35 Mw, and intends to connect the power station at its existing Muggings substation, and take cooling water from the Wellton –Mohawk canal. Western has conducted an interconnection study and concluded that the plant when built could alleviate the problems of constraints into the Yuma area. A facility study is currently underway. The first Siting hearings were conducted in August 2001. The air permit application is complete and submitted, with an expected date for permit issuance in early 2003. El Paso Natural Gas would construct a 60-mile gas pipeline from Quartzsite with another 9-mile pipeline to the plant. The project is developing an interconnection with APS. At this point the in service date is 2005.

A section of new transmission line and about 40 miles of upgrades to Westerns 161 kV transmission line would have to be constructed.

10. Conclusions and Recommendations

10.1 Steps Taken by Industry in Response to First Biennial Transmission Assessment, 2000-2009

The electric industry responded formally to the findings in the first Biennial Transmission Assessment in a variety of ways. A renewed emphasis was placed on regional transmission planning, transmission plants are being planned to increase transmission capacity out of the Palo Verde hub, local transmission import constraints are being better defined, and major service concerns in southeastern Arizona are being addressed. A short summary of each topic is provided below.

10.1.1 Regional Transmission Planning Effort

Given the diverse location of load pockets, generation resources and Merchant Plant development, the Arizona utilities agreed that a regional transmission planning effort is needed to assess the EHV transmission needs and opportunities in the central Arizona area. Hence, the utilities agreed to form the Central Arizona Transmission System study group in 2001, in which all the Arizona transmission utilities, Staff and other interested parties are participants.

The CATS study group has made rapid strides since its formation, and has completed studies related to the identification of alternative EHV transmission facilities in the Central Arizona area. The CATS study has proceeded in several phases, and the group has completed draft reports on the first two phases and is in the process of initiating its Phase III efforts.

Based on the success of the CATS EHV study effort, other related ongoing transmission projects such as the High Voltage transmission study between Phoenix and Tucson and the proposed Arizona-California interstate study project are also being pursued by the CATS study participants . The PNM's Arizona –Sonora Mexico Transmission project is already participating in the CATS study activities.

10.1.2 The Palo Verde Hub Assessment

The first BTA highlighted the inadequacy of the existing Palo Verde transmission system to deliver the total capacity from all the new merchant plants connecting to the PV Hub. Plans for new transmission lines emanating from the Palo Verde Hub have emerged from the CATS studies and recent power plant proposals. In addition, a detailed PV Hub Risk Assessment study was initiated by APS and SRP. As part of this study, catastrophic events like the (N-3) and (N-4) types of contingencies are being studied, and the Hub reconfiguration after such outages is being evaluated.

10.1.3 Import Constraint Zones

In response to the concerns raised by Staff in the first BTA on three transmission import constraint zones (Phoenix, Tucson, and Yuma), the Arizona utilities have become more rigorous in defining the limitations of import constrained load zones. Identification and evaluation of alternative solutions are beginning to emerge. In other words, utilities now acknowledge there is a need to refine the balance between adding local generation and building new transmission infrastructure in order to alleviate the import constraints.

10.1.4 Southeastern Arizona

With regard to Staff's concerns on the inadequacy of transmission in the Southeastern Arizona and the consequent risk of service interruptions, the transmission utilities in the region are coordinating their transmission planning efforts to improve the system adequacy. Citizens has responded to Staff's assessment with regard to the need for additional transmission serving the Santa Cruz County. A second transmission line to Nogales has received a CEC and is currently going through the federal EIS process. Similarly, Citizens has proposed 115 kV capacitors to remedy the effects of loss of that new line due to an outage.

10.1.5 Power Flow and Stability Analysis

All parties have effectively responded to the requirement that power flow and stability analysis reports supporting planned facilities be submitted with their ten-year plans. Staff finds those technical reports were both sufficient and of suitable quality.

10.2 Adequacy of Planned System Facilities

10.2.1 Transmission Import Constraint Zones

Transmission import constraint zones within the Arizona transmission grid are still an area of concern. While the import constraint issues in certain load pockets are being addressed, the measures taken in others are still inadequate. Since the first BTA, the load pockets in Santa Cruz County and Mojave County are also becoming import constrained due to the overload of facilities feeding into those areas.

The measures contemplated by APS in the Yuma area appear to offer a variety of solutions that could alleviate the import constraints. The proposed measures depend on a combination of local generation (existing and new) and APS' share of the lines feeding into Yuma area, and the planned 230 kV transmission line from Gila Bend to Yuma by 2006.

TEP is taking measures to increase the import capability into Tucson area through joint transmission projects with APS, SRP, SWT Coop and CUC, in addition to depending on local generation. However, TEP also addressed the concern related to local voltage support by running local generation. Thus, TEP's proposed solution seems to alleviate the import constraint problem, assuming the proposed transmission projects are completed in a timely manner.

The utilities serving the Phoenix area have proposed a combination of Valley Transmission projects to relieve the import constraints in the Phoenix area, in addition to depending on local generation. As the transmission constraint for the Phoenix Valley changes over time from a transmission import capability to a system voltage limit, a complex set of measures has to be considered to assure system adequacy. From the analysis of the measures proposed by the Valley utilities, several issues remain unanswered with regard to the proposed solution. The issues related to Megavar margin improvement, effect of local generation outages, dispatch levels of local generation to provide the needed load serving capability, and installing reactive power devices locally to improve the voltage support need to be addressed in greater detail.

In the Santa Cruz County area, there is limited local generation, and until the proposed transmission projects near the Gateway substation are completed the import constraint problem will persist. The existing transmission capability is inadequate to serve the load in this area under contingency conditions.

In Mojave County, the transmission path into the County is owned by WAPA and its capacity is fully subscribed. There is inadequate local generation, and the Merchant plants in the area have no contractual agreements in place to run the generation to alleviate the local import constraints. Hence, the transmission system in the area is inadequate to relieve the import constraints.

10.2.2 Local Transmission System Inadequacies

The load in local areas is growing and there is not enough local transmission in some local areas to meet the projected load growth. There is inadequate underlying transmission at the 230/138/115 kV levels to meet the growth in Central Arizona. Although there are good EHV transmission overlays at the 345 kV and 500 kV levels through the CATS efforts, there is inadequate transmission capacity to serve the projected needs of customers. Hence, the HV transmission system servicing this area needs to be investigated further, and transmission plans developed.

Transmission systems of Arizona utilities are also intertwined with the WAPA transmission in the Northern and Southern Arizona areas. WAPA transmission is built to meet the needs of its long-term preference customers, and participation with other utilities can materialize only through trust accounts where the upgrades have to be paid by the users. Concerns related to non-availability of Western's transmission capacity for Arizona utilities have been identified in several areas, namely, Kingman, Flagstaff, Yuma, and Santa Cruz County. This introduces a degree of uncertainty in transmission upgrades, and needs to be resolved to the benefit of Arizona consumers.

In the Northern Arizona area, there is not enough transmission to serve the projected loads after 2006, and no concrete proposals are in place to address this issue.

In the Southeastern Arizona region, transmission reinforcement measures taken by SWT Coop, TEP, and CUC are adequate to serve the customer load, and reduce the need for Remedial Action Scheme (RAS) during multiple contingencies.

10.2.3 Palo Verde System Constraints

Palo Verde system constraints continue to be an area of concern, with inadequate transmission to accommodate the additional generation capacity at the hub. Hence, curtailment procedures are still necessary to limit the output of new power plants. Given the commercial importance of the PV Hub, the transmission adequacy issues have to be addressed, possibly in a framework similar to CATS, in order to take full advantage of the total generation capacity available at the Hub.

10.3 Recommendations

- Continue with the "Guiding Principles for ACC Staff determination of Electric System Adequacy and Reliability " to aid Staff in the determination of adequacy and reliability of power plant and transmission line projects.
- Continue with the stipulation of the requirement of two or more lines out of each plant's switchyard to meet (N-1) contingency criteria without relying on remedial actions such as generator tripping or load shedding.
- Develop policies and practices that maximize the opportunities for resource access at feasible costs in order to improve local area transmission development.
- Establish new collaborative study groups similar to CATS for studying significant projects such as Palo Verde Area Transmission and Palo Verde Hub Risk assessment, Phoenix-Tucson Corridor, and inter-state transmission projects. Such collaborative efforts contribute to cost effective and technically feasible plans.
- Transmission providers should investigate and study in a collaborative fashion local area import constraints, similar to the efforts by APS and SRP on the Phoenix area; the ACC

should establish guidelines and procedures with regard to local voltage and Var support, extent of dependency on local generation to serve load, and the related Reliability Must Run requirements. In addition, guidelines shall be stipulated with regard to considering generation contingencies when evaluating the benefits of local generation to alleviate import constraints.

- ACC shall continue to require power flow and stability analysis reports to be accompanied with Interconnection requests from Merchant Plant developers.
- ACC shall encourage collaborative activities between the transmission providers and merchant plant developers in order to maximize the benefits of generation resources and cost –effective transmission interconnections.
- Staff needs the ability to perform independent technical studies in the future in order to make an independent assessment of the plans submitted by the transmission providers and merchant plant developers.

Appendix A
Guiding Principles for
ACC Staff Determination of
Electric System Adequacy and Reliability

This document serves the dual purpose of providing the guiding principles for ACC Staff determination of electric system adequacy and reliability in the two areas of transmission and generation.

Transmission

A.R.S §40-360.02E obligates the Arizona Corporation Commission (ACC) to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona. Current state statutes and ACC rules do not establish the basis upon which such a determination is to be made. Therefore, ACC Staff will use the following guiding principles to make the required adequacy and reliability determination until otherwise directed by state statues or ACC rules.

4. Transmission facilities will be evaluated using Western Systems Coordinating Council (WSCC), or its successor's, Reliability Criteria for System Planning and Minimum Operating Reliability Criteria.
5. Transmission planning and operating practices traditionally utilized by Arizona electric utilities will apply when more restrictive than WSCC criteria.
6. Compliance with A.C.C. R14-2-1609.B[1] will be established by analysis of power flow and transient stability simulation of single contingency outages (N-1) of generating units, EHV and local transmission lines of greater than 100 kV nominal system voltage, and associated transformers. Reliance on remedial action such as generator unit tripping or load shedding for single contingency outages will not be considered an acceptable means of compliance with this rule.

[1] R14-2-1609.B refers to the obligation of Utility Distribution Companies to assure that adequate transmission import capability and distribution system capacity are available to meet the load requirements of all distribution customers within their service area.

Generation

Pursuant to A.R.S. §40-360.07, the ACC must balance, in the broad public interest, the need for adequate, economical, and reliable supply of electric power with the desire to minimize the effect on the environment and ecology of the state when considering the siting of a power plant or transmission line. The laws of physics dictate that generation and transmission facilities are inextricably linked when considering the reliability of service to consumers. Therefore, it is appropriate that both components must be considered when siting a power plant. ACC Staff will use the following guiding principles to make the required adequacy and reliability determination for siting generation until otherwise directed by state statues or ACC rules.

The best utility practices historically exhibited in the evolution of Arizona's generation and transmission facilities should be continued in order to promote development of a robust energy market. Non-discriminatory access to transmission and fair and equitable business practices must also be maintained and the service reliability to which the state is accustomed must not be compromised. Therefore, Staff support of power plant Certificate of Environmental Compatibility applications will be conditioned as set forth below.

ACC Staff support of power plant Certificate of Environmental Compatibility applications will be contingent upon the applicant providing, either in the application or at the hearing, evidence of items 1-3 below:

7. Two or more transmission lines must emanate from each power plant switchyard and interconnect with the existing transmission system. This plant interconnection must satisfy the single contingency outage criteria (N-1) without reliance on remedial action such as generator unit tripping or load shedding.
8. A power plant applicant must provide technical study evidence that sufficient transmission capacity exists to accommodate the plant and that it will not compromise the reliable operation of the interconnected transmission system.
9. All plants located inside a transmission import limited zone "must offer" all Electric Service Providers and Affected Utilities serving load in the constrained load zone, or their designated Scheduling Coordinators, sufficient energy to meet load requirements in excess of the transmission import limit.

ACC Staff support of power plant Certificate of Environmental Compatibility applications will further be contingent upon the Certificate of Environmental Compatibility being conditioned as provided in items 4-6 below:

10. The Certificate of Environmental Compatibility is conditioned upon the plant applicant submitting to the ACC an interconnection agreement with the transmission provider with whom they are interconnecting.

11. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of WSCC, or its successor, and filing a copy of its WSCC Reliability Criteria Agreement or Reliability Management System (RMS) Generator Agreement with the ACC.
12. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of the Southwest Reserve Sharing Group, or its successor, thereby making its units available for reserve sharing purposes.

Approved by:

(Original Signed by Deborah R. Scott)

Deborah R. Scott
Director
Utilities Division

This date: (2/8/00)

DRS/jds:ESAR.doc

Appendix D
List of Reference Documents

13. ACC Rule A.R.S. 40-360.02
14. ACC Rule 1606.B
15. ARS Section 40-360-02-B
16. WECC Reliability Criteria found at http://www.wecc.com
17. NERC Planning Standards found at http://www.nerc.com
18. Jerry D. Smith, ACC, "Arizona's Best Engineering Practices", Staff pre-filed comments for the Gila Bend Power Plant Hearing, Docket No. L-00000V-00-01016, November 9, 2000
19. Federal Energy Regulatory Commission, Standard Market Design, July 31, 2002, Docket No. RM01-12-000
20. U.S. DOE National Transmission Grid Study, May 2002
21. Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association, August 2001
22. WECC Reliability Criteria for Transmission System Planning, May 2001
23. WECC Reliability Management System (RMS) Agreement found at http://wecc.com
24. ACC Staff Report on the Generic Electric Restructuring, Docket No. E-00000A-02-0051, March 22, 2002
25. Direct Testimony of Jerry Smith, March 29, 2002, in the matter of APS request for a partial variance of certain requirements of AAC R14-2-1606, Docket No. E-0135A-01-0822
26. Rebuttal Testimony of Cary Deise on behalf of APS, April 22, 2002, Docket No. E-0135A-01-0822, et al.
27. Electric Restructuring Generic Track A Issues, E-00000A-02-0051, etc. Pages 1456-1633, June 28, 2002
28. Generic Proceedings Concerning Electric Restructuring, APS and TEP, July 23, 2002 (Docket Nos. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069, E-01993A-98-0471
29. WSCC: NERC/WSCC Planning Standards, revised August 7, 2002
30. WSCC: Minimum Operating Reliability Criteria, revised March 28, 2001
31. SRP Ten-Year Plan, 2002-2011, Appendix 1, Report on the Phase 1 Study of the CATS, July 20, 2001
32. WestConnect RTO, Docket No. RTO2-000, filed with FERC
33. AAC R14-2-1609D.05
34. ACC Revised Biennial Transmission Assessment, Docket No. E-00000A-01-0120, July 2001
35. APS Ten-Year Plan, 2002-2011, January 2002

36. SRP 10-Year Plan, 2002-2011, January 2002
37. Tucson Electric Power Company, Amendment to Ten-Year Plan, February 5, 2002
38. Southwest Transmission Cooperative, Inc., Ten-Year Plan, 2002-2011, January 2002
39. Citizens Communications Company, Arizona Electric Division, Ten-Year Plan, 2002-2011, January 30, 2002
40. WAPA-Desert Southwest Region (DSW) Ten-Year Plan, February 26, 2002
41. Public Service Company of New Mexico, Ten-Year Plan, 2002-2011, January 30, 2002
42. El Paso Electric Company's 2002 Filing of Arizona Ten-Year Plan, 2002-2011, January 2002
43. Texas-New Mexico Power Company, Ten-Year Plan, Electric Transmission Lines, 28th Report, January 18, 2002.
44. NRG MexTrans, Inc. Ten-Year Plan, January 31, 2002
45. Ten-Year Plan Filing of Allegheny Energy Supply Company, LLC, Letter of January 30, 2002
46. Ambos Nogales Generating Station, LLC and Maestros Group, LLC, Ten Year Plan, January 31, 2002
47. Desert Energy, LLC Ten-Year Plan, (E-00000D-02-0065), January 28, 2002
48. Reliant Energy Signal Peak, LLC Ten-Year Plan, 2002-2011, January 31, 2002
49. Panda Gila River, LP, Ten Year-Plan, Letter of January 31, 2002 from Fennemore Craig
50. Facilities Study for Gila River Project for APS (By RW Beck), March 2000
51. Duke Energy Arlington Valley, LLC Ten Year Plan, Docket No: L-00000P-01-0117, Letter of January 24, 2002 (Need the Report)
52. Gila Bend Power Project, Ten-Year Plan, January 30, 2002
53. Toltec Power Station, LLC, Ten-Year Plan, January 29, 2002
54. Letter from Martinez & Curtis, P.C., on Wellton-Mohawk Ten-Year Plan, January 31, 2002
55. Bowie Power Station, LLC, Ten-Year Plan, January 29, 2002
56. Central Arizona Project (CAP), Letter from Central Arizona Water Conservation District, January 31, 2002
57. Letter from Doug Fant of Power Up Corporation on Ten-Year Plan, January 28, 2002
58. System Impact Study for Sundance Energy Project, Stage One, by Desert Southwest Region, May 2001
59. Arizona Power Plants-Technical Summary, June 24, 2002
60. Reporter's Transcript of Workshop Proceedings, Volume I, July 30, 2002
61. Reporter's Transcript of Workshop Proceedings, Volume II, July 31, 2002
62. ACC Condition #23

63. SRP Ten-Year Plan, 2002-2011, Appendix 2, Report on the Preliminary Study for the Palo Verde Interconnection

64. Draft Report on the Phase II Study of the Central Arizona Transmission System (CATS), August 16, 2002

65. http://www.cc.state.az.us/utilities/electric/xmn.pdf

66. ACC Rule 1609-B

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68. Decision No. 65154, Docket No. E-00000A-02-0051, et al., September 6, 2002

69. Ibid, page 25 at line 23

70. Ibid, Finding of Fact 40

71. Ibid, Finding of Fact 41

Appendix E
List of Workshop Attendees
July 30-31, 2002

Ali Amirali
Calpine Western Region
6700 Koll Center Parkway, Suite 200
Pleasanton CA 94566
925-600-2009

Arlene C. Arviso
Program Manager
Dine Power Authority
P.O. Box 3239
Window Rock AZ 86515
623-871-2133
Fax: 623-871-4046

Ken Bagley
R.W. Beck
14635 N. Kierland Boulevard, Suite 130
Scottsdale AZ 85254
480-367-4282
kbagley@rwbeck.com

Ed Beck
Supervisor
Tucson Electric Power Company
Tucson AZ
520-745-3276
ebeck@tucsonelectric.com

David Berry
LAW Fund
P.O. Box 1064
Scottsdale AZ 85252-1064
azbluhill@aol.com

Paul Bullis –Alternate-Chairman
Office of the Attorney General
1275 West Washington
Phoenix AZ 85007

Jim Charters
Planning Manager
Western Area Power Administrator
P.O. Box 6457

Phoenix AZ 85005-6457
602-352-2586
charters@wapa.gov

Resal Craven
Director of Engineering
Citizens Communications
Arizona Electric Division
2901 North Central Avenue, Suite 1660
Phoenix AZ 85012
602-532-0973
rcraven@czn.com

Cary B. Deise
Director
Arizona Public Service Company
502 South Second Avenue
Phoenix AZ 85003
602-250-1232
Cary.Deise@aps.com

Randy Dietrich
Salt River Project
P.O. Box 52025
Phoenix AZ 85072-2025
602-236-4311
rgdietri@srpnet.com

Tom Duane
Public Service Company of New Mexico
2401 Aztec Road NE
MS Z245
Albuquerque NM 87105
505-855-6275

Rebecca Eickley
City of Scottsdale
7447 E. Indian School
Scottsdale AZ 85251
480-312-7084
reickley@ci.scottsdale.az.us

Bruce Evans

Maricopa County
Facilities Management Department
401 W. Jefferson Street
Phoenix AZ 85003
602-506-8172
bruce.evans@fm.maricopa.gov

Doug Fant
Power Up Corporation
80 E. Columbus Avenue
Phoenix AZ 85003
915-685-8582

Jeff Guldner
Snell & Wilmer
One Arizona Center
Phoenix AZ 84005
602-382-6271
Fax: 602-382-6070
jguldner@swlaw.com

Gregg A. Holtz, Alternate
Arizona Department of Water Resources
500 North Third Street
Phoenix, AZ 85004-3903

Brian K. Keel
SRP
P.O. Box 52025
Phoenix AZ 85072-2025
602-236-0970
bkkeel@srpnet.com

Barbara Klemstine
Manager, Regulation
Pinnacle West
P.O. Box 53999
Station 9909
Phoenix AZ 85072
602-250-4563
Fax: 602-250-3399

Barbara.klemstine@pinnaclewest.com

Robert Kondziolka
Manager
Salt River Project
P.O. Box 52025
M.S. POB100
Phoenix AZ 85072-2025
602-236-0971
rekondzi@srpnet.com

Rod Leas
NRG
75 Many Levels Road
White Bear Lake MN 55110
612-373-5358

William Lesikar
Power Up Corporation
12225 Greenville Avenue, Suite 950
Dallas TX 75243
972-889-2100 ext. 114
blesikar@elmridge.net

Sam Lipman
Desert Energy
13257 North 94th Place
Scottsdale AZ 85260
480-860-4568
azenergy@hotmail.com

Attorney Bob Lynch
340 E. Palm Lane
Phoenix AZ
602-254-5908
rslynchaty@aol.com

Angel Mayes
Bureau of Land Management
Sonoran Desert National Monument
21605 N. 7th Avenue
Phoenix AZ
623-580-5502

Jeff McGuire

P.O. Box 1046
Sun City AZ 85372

Mark McWhirter
Director, Energy Office
Department of Commerce
3800 North Central, Suite 1200
Phoenix AZ 85012

Steve Mendoza
Chief Engineer
Arizona Power Authority
1810 West Adams
Phoenix AZ 85007
602-542-4263 ext. 25
steve@powerauthority.org

Paul Michaud
Martinez & Curtis, P.C.
2712 N. 7th Street
Phoenix AZ 85006

Paul Michaud
Wellton-Mohawk Generating Facility
3074 E. Park Avenue
Gilbert AZ 85234

Jay Moyes
Moyes Storey Ltd.
3003 N. Central
Phoenix AZ 85012
602-604-2106
jimoyes@lawms.com

Frederick Ochsenhirt
Dickstein Shapiro Morin & Oshinsky
2101 L Street NW
Washington DC 20037
202-861-9161
Greg Patterson, CPA
gpattersoncpa@aol.com

Greg Ramon
TECO Energy
P.O. Box 111
Tampa FL 33601

Charles Reinhold
WestConnect
P.O. Box 88
Council ID 83612
208-253-6916
reinhold@primenet.com

Anthony H. Rice, P.E.
MWH Energy & Infrastructure, Inc.
4820 South Mill Avenue, Suite 202
Tempe AZ 85282

Gary Romero
SRP
P.O. Box 52025
Phoenix AZ 85072-2025
602-236-0974
geromero@srpnet.com

Chuck Russell
SRP
P.O. Box 52025
Phoenix AZ 85072-2025
602-236-0975
csrussel@srpnet.com

Patrick J. Sanderson
Arizona Independent Scheduling Administrator
615 South 43rd Avenue
P.O. Box 6277
Phoenix AZ 85009
602-352-3532
psanderson@az-isa.org

Pat Schiffer
Arizona Department of Water Resources
500 North Third Street
Phoenix, AZ 85004-3903
H. Max Shilstone
Manager
Duke Energy North America/Arlington Valley Energy
5200 Westheimer Court
Houston TX 77056-5310
713-627-6572

Chuck Skidmore
City of Scottsdale

P.O. Box 4189
Scottsdale AZ 85261
480-312-7606

A. Wayne Smith
6106 South 32nd Street
Phoenix, AZ 85040

Honorable Sandie Smith
Pinal County Board of Supervisors
575 North Idaho Road, #101
Apache Junction, AZ 85219

Rob Speers
MWH Energy & Infrastructure, Inc.
4820 South Mill Avenue, Suite 202
Tempe AZ 85282
480-755-8201
Fax: 480-755-8203
Rob.speers@mwhglobal.com

Rob Taylor
Jennings Strauss
201 W. Washington
Phoenix AZ 85007

Richard W. Tobin II
Deputy Director
Arizona Department of Environmental Quality
3033 North Central Avenue
Phoenix AZ 85007

Margaret Trujillo
Maricopa County RBHA
Service Integration Officer
444 North 44th Street, Ste. 400
Phoenix, AZ 85008